BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 165

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY	)
	)
Application for Approval of a Hydro Generation Adjustment Tariff.	)
	)

DIRECT TESTIMONY OF

RANDALL J. FALKENBERG

ON BEHALF OF

THE INDUSTRIAL CUSTOMERS OF NORTHWEST UTILITIES

February 14, 2005

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am a utility rate and planning consultant holding the position of President and Principal with the firm of RFI Consulting, Inc. ("RFI"). I am appearing in this proceeding as a witness for the Industrial Customers of Northwest Utilities ("ICNU").

Q. PLEASE BRIEFLY DESCRIBE THE NATURE OF THE CONSULTING SERVICES PROVIDED BY RFI.

A. RFI provides consulting services in the electric utility industry. The firm provides expertise in electric restructuring, system planning, load forecasting, financial analysis, cost of service, revenue requirements, rate design, and fuel cost recovery issues.

I. QUALIFICATIONS

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. Exhibit ICNU/101 describes my education and experience within the utility industry. I have more than 25 years of experience in the industry. I have worked for utilities, both as an employee and as a consultant, and as a consultant to major corporations, state and federal governmental agencies, and public service commissions. I have been directly involved in a large number of rate cases and regulatory proceedings concerning the economics, rate treatment, and prudence of nuclear and non-nuclear generating plants.

During my employment with EBASCO Services in the late 1970s, I developed probabilistic production cost and reliability models used in studies for 20 utilities. I personally directed a number of marginal and avoided cost studies performed for compliance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"). I also participated in a wide variety of consulting projects in the rate, planning, and forecasting areas.

In 1982, I accepted the position of Senior Consultant with Energy Management Associates ("EMA"). At EMA, I trained and consulted with planners and financial analysts at several utilities using the PROMOD III and PROSCREEN II planning models.

In 1984, I was a founder of J. Kennedy and Associates, Inc. ("Kennedy"). At that firm, I was responsible for consulting engagements in the areas of generation planning, reliability analysis, market price forecasting, stranded cost evaluation, and the rate treatment of new capacity additions. I presented expert testimony on these and other matters in more than 100 cases before the Federal Energy Regulatory Commission ("FERC") and state regulatory commissions and courts in Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Louisiana, Maryland, Michigan, Minnesota, New Mexico, New York, North Carolina, Ohio, Oregon, Pennsylvania, Texas, Utah, West Virginia, and Wyoming. Included in Exhibit ICNU/101 is a list of my appearances.

In January 2000, I founded RFI Consulting, Inc. with a comparable practice to the one I directed at Kennedy.

Q. HAVE YOU PREVIOUSLY APPEARED IN ANY PROCEEDINGS BEFORE THE OREGON PUBLIC UTILITY COMMISSION?

A. Yes. I filed testimony in four Portland General Electric ("PGE" or the "Company") cases: UE 137 and UE 139 in 2002, UE 149 in 2003, and UE 161 in 2004. In those cases, I addressed PGE's Resource Valuation Mechanism ("RVM") and PGE's request for a power cost adjustment mechanism ("PCA"). In addition, I filed testimony in three recent PacifiCorp rate proceedings in Oregon (UE 111, UE 116, and UE 134). The issues I addressed in all three cases were ultimately settled. In those cases, I addressed issues related to modeling of net power costs and a PCA. I also filed testimony in UM 995, quantifying the disallowances proposed by other ICNU witnesses and the costs of a hydro energy deficit experienced by that company. Finally, I filed testimony regarding PacifiCorp's inter-jurisdictional allocation issues in UM 1050.

Q. HAVE YOU APPEARED AS AN EXPERT IN OTHER PROCEEDINGS INVOLVING FUEL OR POWER COST ISSUES?

A. Yes. I have been involved in a number of PacifiCorp proceedings in California, Utah, Washington, and Wyoming, where I testified concerning power cost issues. In Texas, I have also been involved in a number of power cost related cases. Finally, I have appeared in a number of other cases where fuel or purchased power costs were at issue. Exhibit ICNU/101 summarizes other cases in which I have appeared.

II. INTRODUCTION AND SUMMARY

Q. WHAT IS THE PURPOSE OF THIS TESTIMONY?

A. ICNU has asked me to examine PGE's proposed Hydro Generation Adjustment ("HGA") tariff (Schedule 128) and the justification provided for this proposal. I have identified a number of problems with PGE's HGA proposal.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I have concluded as follows:

1. PGE has failed to provide compelling and persuasive justification for the HGA. The HGA proposal is little more than a rate increase request in disguise, supported by PGE's belief that its return on equity ("ROE") is too low. However, unlike a normal rate case, the Company offers no projection of the customer impact, no cost justification, and no requested ROE. The Commission should only consider the HGA in the context of a full general rate case, where all appropriate issues can be considered.

2. Adoption of the HGA would amount to a fundamental shifting of risk between PGE's investors and ratepayers. It would undermine the concept of rate finality and, as PGE admits, likely increase costs to ratepayers by an unknown amount.

3. Examination of the facts underlying Exhibit PGE/302 presented by Messrs. Niman and Tinker demonstrates that Oregon has never used a mechanism similar to the one proposed here and has never adopted a permanent comprehensive PCA for PGE. Past Commissions have tended to approve such mechanisms only in times when energy costs were quite volatile or other unusual or extreme circumstances prevailed. Further, the mechanisms approved in the past have generally been intended as temporary adjustments to deal with specific short-term problems.

4. PGE's rate schedules are already burdened with a plethora of riders and special adjustment tariffs. The Commission should seek to simplify PGE's rate structure, not complicate it further by approving the HGA.

5. The illustration of the impact of the HGA presented by Mr. Kuns (Exhibit PGE/702) does not reflect the relationship between market prices and hydro generation assumed in Exhibit PGE/301 (used as the basis for Ms. Lesh's testimony). I provide such an analysis.

Q. WHAT IS YOUR OVERALL RECOMMENDATION?

A. I recommend that the Commission reject PGE's proposed HGA and any other form of a PCA at this time. Should the Commission be convinced of the need for an additional mechanism to reduce the variability in PGE's earnings, I recommend PGE enter into a "hedge" transaction with ratepayers that would provide earnings stability for the Company, but provide ratepayers and shareholders a fair opportunity to match payments and receipts over time. In contrast, PGE's HGA proposal places ratepayers in the position of accepting an unbounded risk, with little real opportunity for a compensatory return in the future. The Commission should not force ratepayers to assume risks other counterparties are unwilling to accept.

<u>Justification for the HGA</u>

Q. HOW DOES MS. LESH DESCRIBE THE HGA?

A. Ms. Lesh describes the HGA as a "*simple, on-going, symmetrically-designed, automatic adjustment clause that tracks the costs associated only with the difference between forecasted and actual hydro generation.*" PGE/100, Lesh/3 (emphasis added).

Q. IS THIS AN ACCURATE DESCRIPTION OF THE HGA PROPOSAL?

A. No. First of all, by Ms. Lesh's own admission, the HGA is not symmetrically designed because it is not likely to be revenue neutral. Ms. Lesh testifies that the impact of hydro variations on Net Power Costs ("NPC") is skewed because poor hydro conditions tend to cause higher market prices, while good hydro conditions have an effect of lowering market prices. PGE/100, Lesh/10. Assuming that this is an accurate assessment, then the probable cost to ratepayers of the HGA when hydro deficits occur is likely to exceed the benefits that will occur when there is a hydro surplus. In fact, in Exhibit PGE/301, PGE develops an analysis that demonstrates the asymmetric nature of hydro cost variations, showing that in "bad years" the costs could be $52-$93 million higher, while in good years costs would be $28-41 million lower. PGE/100, Lesh/9 (corrected Dec. 21, 2004). Because PGE proposes to recover additional costs (outside of the small deadband of $2.5 million), the impact on ratepayers is not symmetrical. Indeed, assuming PGE's premise that hydro deficits increase costs by more than hydro surpluses reduce them, the HGA amounts to a request for a rate increase disguised as a "simple, symmetrically-designed, automatic adjustment clause." PGE/100, Lesh/3. When all is said and done, the HGA proposal amounts to a single-issue rate case in which PGE is seeking an increase in revenues.

Q. THE COMPANY RELIES SUBSTANTIALLY ON THE ANALYSIS OF HYDRO COST VARIATION DEVELOPED IN EXHIBIT PGE/301. ARE THESE FIGURES BASED ON ANY EMPIRICAL ANALYSIS OR ARE THEY MERELY ILLUSTRATIVE EXAMPLES?

A. Based on PGE's response to ICNU data request ("DR") No. 1.1, the figures generated by PGE's study of the impact of hydro cost variation (from Exhibit PGE/301, referenced above) are merely illustrative, and are not based on any actual data or any empirical analysis. While the concept that hydro deficits will increase costs more than a hydro surplus will reduce them might be reasonable, the figures presented by the Company are nothing more than an unsupported example. Consequently, Ms. Lesh's contention that the ROE impacts of these variations are *large in relation* to PGE's ROE, but *small in comparison to* *customer's average rates,* depends entirely on an illustrative example rather than real evidence. PGE/100, Lesh/9.

Q. COMMENT ON MS. LESH'S STATEMENT THAT THE IMPACT OF HYDRO VARIATIONS WOULD BE SMALL ON RATEPAYERS.

A. I find these comments disturbing. In essence, Ms. Lesh is arguing that ratepayers have "deep pockets" compared to investors, and can therefore absorb hydro risks without really noticing it. This should not be the basis upon which the Commission decides such issues. Rather, the Commission should assign hydro risks on the basis of conventional ratemaking practices. This would mean that investors (who have the discretion to invest or not) should bear appropriate risks, while ratepayers (who are captive customers) should not.

Q. DOES THE HGA TRACK THE ACTUAL COST IMPACTS RESULTING FROM HYDRO VARIATIONS?

A. No. It would be more accurate to say that it tracks *hypothetical* cost impacts, not actual, because PGE proposes to price out any hydro surplus or deficit based on a wholesale market price index. PGE provides no evidence to demonstrate that this index provides an accurate measure of the actual cost of hydro variations.

PGE implicitly assumes that it will purchase all replacement power at market index prices. In all likelihood, this will overstate the cost of hydro variations because the Company has the option to run its gas-fired units when hydro generation is below normal and gas prices are low (relative to market). PGE provides no evidence supporting the assumption that it must make all purchases at market.

Further, PGE stated in its response to ICNU DR No. 1.14 that the Company has no analysis to "determine whether we systematically purchase power at prices above or below any published index." ICNU/102, Falkenberg/1. In effect, PGE does not know whether the use of an index price even provides an accurate representation of the prices the Company actually pays for the power it purchases. In the end, PGE has no evidence to demonstrate that this index accurately represents the cost of hydro variations or that it even is representative of the purchases it actually makes.

Q. HAS PGE DEVELOPED AN ESTIMATE OF HOW MUCH THIS PROPOSAL WILL COST OR SAVE RATEPAYERS?

A. No. Ms. Lesh testifies as follows:

> We have *no way of knowing* if, over the remaining life of these resources, "good" water years will balance with "bad" water years. We have *no idea* what the price of extra or missing hydro production will be. We have no idea what the distribution of water years will be - whether the NW will experience five "good" years in a row or five "bad" years in a row or any number of other possibilities.

PGE/100, Lesh/14 (emphasis added).

Q. PLEASE SUMMARIZE THE PGE HGA PROPOSAL BASED ON THIS DISCUSSION.

A. PGE acknowledges that the HGA proposal will likely result in an increase in customers' rates over time, but it has "*no idea*" of the amount. The Company proposes to pass on hypothetical cost increases to customers, but provides *no evidence* to suggest these costs are related to the actual cost of hydro variability.

Q. HOW THEN DOES PGE JUSTIFY ITS ATTEMPT TO OBTAIN THIS UNKNOWN RATE INCREASE TO PASS ON THESE HYPOTHETICAL HYDRO COSTS?

A. Ms. Lesh argues that allowing the HGA will cost customers less than compensating PGE's investors for PGE's risk related to hydro variability by increasing the Company's cost of capital. PGE/100, Lesh/14. Again, however, PGE provides no real analysis (not even a hypothetical one) to "close the loop" and demonstrate that the costs of this proposal to ratepayers will be outweighed by the assumed benefit. Indeed, PGE stated in its response to ICNU DR No. 1.20 that Dr. Makholm has not performed any analysis to quantify these effects, and he acknowledges that it would be very difficult to do so reliably and objectively. ICNU/103, Falkenberg/1. Thus, PGE proposes to pass on hypothetical and unknown costs to customers on the basis of obtaining an unknown benefit. PGE merely asserts this is a good deal for customers, based only on its own self-interested judgment.

Q. IF THE HGA WERE ADOPTED, WOULD PGE COMPENSATE RATEPAYERS BY FLOWING THROUGH THE LOWER COST OF CAPITAL?

A. No. Dr. Makholm testifies that PGE's ratepayers are not now compensating investors for the hydro risks because members of the comparison group of companies used to determine PGE's ROE in its last general rate case do not face comparable risks. PGE/500, Makholm/3-4. PGE appears to view the transfer of its hydro risk to ratepayers as something that the Company is "due."

Q. PLEASE COMMENT.

A. When PGE's request is boiled down to its basic elements, the Company is requesting a rate increase because it believes its ROE is not high enough. While PGE's proposal will not necessarily cause an increase in rates every single year, ratepayers will pay more than under the status quo over time. Unlike a traditional rate increase request, however, PGE proposes no definite ROE, no specific rate increase, and provides no estimates of customer impacts. Nor does PGE propose to look at any actual costs or its overall level of earnings as part of this "stealth" rate increase.

Q. IS THIS A REASONABLE PROPOSAL?

A. No. The proper forum for determination of overall rate levels is a general rate case. If the Company believes its ROE is inadequate, it can file a general rate case and attempt to prove its case. Because PGE is proposing far-reaching changes to the regulatory status quo, the best forum for deciding this kind of issue would be in the context of a full general rate case. Lacking that, I recommend that Commission reject the HGA proposal at this time and not entertain future requests unless coupled with a general rate proceeding.

Q. MS. LESH TESTIFIES THAT THE "DURATION" OF HYDRO RESOURCES IS KEY IN FRAMING THE ISSUES IN THIS DOCKET. PGE/100, LESH/8. PLEASE COMMENT.

A. Ms. Lesh discusses the fact that in the future the hydro resources will cost more and produce less output due to contract expirations, biological and environmental constraints, and competing water uses. While this may be true, these problems have little to do with the alleged need for the HGA. Ms. Lesh seems to confuse the long-term resource problem of diminishing hydro generation with the short-term problem of unpredictable weather that causes variations in hydro output.[1/] The former problem is something that PGE already may deal with in the RVM process. In most cases, PGE will know in advance what the expected changes to hydro resources will be due to contract expirations and other changing constraints. It is only the latter problem (which is really a manifestation of weather) that creates the circumstances for which the Company seeks relief here.

Q. ARE THERE OTHER REASONS WHY A GENERAL RATE CASE WOULD BE A MORE APPROPRIATE FORUM FOR DISCUSSION OF THESE ISSUES?

A. Yes. There are two very good reasons why a rate case would be a more appropriate forum. First, the Company has not provided any detailed modeling studies and indeed lacks the modeling capabilities to assess the impact of hydro variations on system costs. As noted previously, the modeling results presented in Exhibit PGE/301 are little more than hypothetical examples. Thus, the Commission is left with no basis to judge the true severity or significance of the alleged hydro cost variations. Further, because of this lack of modeling studies, the Commission lacks the results of simulation studies of the HGA that are necessary to make informed decisions as to the best way in which to design such a mechanism. Without simulation results, the proposed HGA is a "stealth" rate increase of unknown magnitude. It clearly would be inequitable to implement a rate increase without the formal protections of a full-blown rate proceeding.

[1/] In fact, a long-term decline in hydro generation would help PGE's problem because it would mean hydro was a smaller portion of its resource mix.

Further, when realistic simulation results are provided, the Commission would be in a much better position to design a revenue-neutral HGA, if it so desires.

Second, a general rate case provides for a much more level playing field. General rate cases provide numerous issues, and parties have more bargaining power. This means that settlements are more likely to result from a general rate case than might be the case in a one-sided situation such as this, where the Company is seeking to expand the scope of costs borne by ratepayers.

Risk Shifting and Rate Finality

Q. DO YOU AGREE WITH PGE THAT THE HGA WOULD TRANSFER RISKS OF HYDRO VARIATION FROM INVESTORS TO CUSTOMERS?

A. Yes. However, the question of whether this is a risk appropriately assigned to consumers or investors, or whether PGE's investors already are adequately compensated for these risks, is subject to debate. PGE contends that it will be less costly for ratepayers to assume responsibility for these risks than to compensate investors (in the form of a higher cost of capital) for them. PGE/100, Lesh/14. However, this is merely an assertion, totally lacking in proof.

The concept of shifting risks from investors to customers seems curious to me, as it flies in the face of conventional ratemaking assumptions. Hydro variation is but one risk faced by investors and probably not the most significant one. Of course, in this case there is no evidence as to the true magnitude of this risk.

Q. CAN YOU PROVIDE SOME EXAMPLES OF OTHER RISKS FACED BY INVESTORS?

A. Certainly. Financial and interest rate risks have always been assumed by investors, and these can certainly be extreme. In October 1987, for example, the stock market dropped by approximately 20% in one day. Likewise, interest rates have gone well above the double-digit level over the past decades. While we are now in what appears to be a period of relatively stable interest rates and financial markets, this has not always been the case. While these risks are potentially substantial, there is very little history of utilities seeking to shift these kinds of risks from investors to ratepayers. However, under PGE's logic, one might argue that the impact on investors is large, while the impact on customers would be small (i.e., ratepayers have deep pockets), so it would be preferable to transfer those risks to ratepayers. I certainly disagree with such an argument, and I expect the Commission would not take it seriously.

Besides financial risk, there are also other risks related to customers' sales and revenue, as well as costs of other kinds of fuels and the wholesale price of electricity. In recent years, load forecast errors have been a major, if not far more significant, cause of power cost variations for PGE. For example, in UE 137, the Company produced an analysis showing that a 5% increase in load would cause a 6.7% increase in net power costs. <u>Re PGE</u>, OPUC Docket No. UE 137, ICNU/102 (Aug. 16, 2002).

In UM 1039, the docket in which the Commission reviewed the prudence of the costs recorded under PGE's 15-month PCA approved in UE 115, the Company acknowledged that overstatement of the load forecast was the leading component in the PCA balance. In fact, the Company indicated that the load forecast error of 7.3% was responsible for more than $70 million of the approximately $80 million PCA balance. Re PGE, OPUC Docket No. UM 1039, PGE/200, Niman-Hager-Tooman/6; PGE/201, Niman-Hager-Tooman/7 (Jan. 30, 2004). Consequently, load forecast variation appears to be a much more significant risk factor for PGE than hydro variation. However, the Company does not propose to transfer this risk from investors to customers. Nor should it.

Q. DOES THE ANNUAL UPDATE TO THE RVM ALREADY PROVIDE THE COMPANY WITH SUBSTANTIAL PROTECTION FROM POWER COST RISKS?

A. Yes. The RVM process already provides substantial protection from market volatility and other factors that produce power cost variances. With the RVM, PGE is allowed to re-estimate its variable power costs once per year and compute the final power costs used in rates (updating the most significant items) *as late as November of each year*. Under the RVM, the power cost estimate is prepared just two months prior to the rate effective period, and none of the underlying data is more than eight to ten months old.

In contrast, the situation would be much different without the RVM. Even if PGE filed a general rate case every year, the power cost estimates reflected in rates would be close to a year out of date by the time rates went into effect. Without an annual rate filing, these costs would remain in effect until the next general rate case was filed. Thus, the RVM provides the Company with a substantial ability to track and respond to power cost changes over time. This is a unique and beneficial set of circumstances that PGE did not enjoy prior to 2001, and that PacifiCorp does not currently enjoy. The RVM is really quite similar to a PCA except that a tracking mechanism (true-up to actual) is not used. The HGA would expand the RVM to now include a hydro tracking mechanism (although not a true-up to actual cost as discussed above).

Q. HAS THE RVM BEEN BENEFICIAL FOR CUSTOMERS?

A. I do not believe so. Up to this point, the total NPC collected in rates has increased substantially due to the RVM. Thus, customers have already absorbed much of the risk of increased power costs.

Q. IS THERE A SOUND PHILOSOPHICAL REASON THAT REGULATORS SHOULD OPPOSE THE USE OF AN ADDITIONAL TRACKING MECHANISM?

A. Yes. Under the proposed HGA, the concept of rate finality is violated. Customers may not know the full cost of their consumption for several years afterwards. PGE itself admitted that this is a problem with tracking mechanisms in its testimony in UE 113:

> Philosophically, we dislike the idea of a true-up. Even with use of variance sharing, the true-up weakens the utility's incentives to manage its business and it seriously detracts from the value customers receive in knowing that the price they pay for electricity used today is the actual price. Few people would be willing to buy an airline ticket if, several weeks after the flight, the airline could send another bill - or a refund check for that matter - based on the final count of seats taken in the plane or some such set of actual inputs. People generally like price certainty. *Until our customers have a choice of products, we would prefer not to require all to choose an electricity product that does not include price finality as a feature.*

<u>Re PGE</u>, OPUC Docket No. UE 113, PGE/100, Pollock-Lesh/13 (Aug. 16, 2000) (emphasis added).

Price finality is quite important to large consumers who attempt to manage their energy costs. Long-term production decisions must be made based on known or expected power costs. If consumers do not know what power actually is going to cost, their ability to make intelligent investments in energy savings investments is compromised, resulting in higher costs to society. Increasing the uncertainty in overall prices will ultimately increase the cost of inefficient consumption. Adoption of the HGA would frustrate the customers' goal of minimizing energy costs and would reduce overall efficiency.

Q. DO THE PRINCIPLES THAT TYPICALLY GUIDE THE COMMISSION IN ESTABLISHING REVENUE REQUIREMENT CONTEMPLATE A TRUE-UP OF COSTS TO ACTUAL RESULTS?

A. No. Under traditional ratemaking theory, rates are set based on normalized results of operations, and rates are not trued-up to actual results. Staff described the manner in which the Commission establishes revenue requirement for Oregon utilities in a recent White Paper Regarding the Treatment of Income Taxes in Utility Ratemaking prepared for the Oregon Legislative Assembly:

> The Commission calculates the amount of revenues the utility needs to collect in order to provide adequate service and earn a reasonable return on its investments. That amount of revenues, called the utility's "revenue requirement," is determined during a rate case investigation in which the Commission estimates the utility's costs for a 12-month "test year." Costs include reasonable, ongoing expenses such as employee compensation, fuel costs, depreciation, and taxes. Costs also include a return on rate base, the net book value (not the market value) of the assets or investments used to provide utility service.
>
> In determining a utility's revenue requirement, the Commission establishes rates that provide the company an opportunity—*not a guarantee*—to recover its reasonable costs of providing utility service and earn its authorized rate of return on investments. That is, customers' rates are based on estimates of what costs the utility

> will incur to provide service when the new rates are in effect. It is virtually certain that actual revenues and costs will turn out to be different than the levels estimated for setting the rates. However, it is assumed that changing expenses and revenues will balance out between rate cases. It may be several years before the utility or another party files to reset rates to reflect new levels of revenues and costs. With few exceptions, rates are not adjusted "after the fact" to true up for the revenues and costs that actually occurred.[2/]

"Treatment of Income Taxes In Utility Ratemaking," A White Paper Prepared for The Oregon Legislative Assembly by Public Utility Commission of Oregon Staff at 5 (Feb. 2005) (internal footnotes omitted). Staff's description of the process for establishing revenue requirement demonstrates that rates are based on estimates of costs and revenues, with the understanding that the actual costs and revenues will differ from those estimates. Adopting a mechanism such as the HGA, which effectively will true-up the estimates to the hypothetical cost impact determined by PGE (outside of the minimal deadband), upsets the understanding upon which revenue requirement is based.

<u>Historical Application of Tracking Mechanisms</u>

Q. BASED ON EXHIBIT PGE/302, THE COMPANY CONTENDS THAT POWER COST TRACKING MECHANISMS HAVE BEEN USED FREQUENTLY IN THE PAST. PLEASE COMMENT.

A. Exhibit PGE/302 purports to show that over the period September 1974 to December 2002, PCA mechanisms were in place 43% of the time. On this basis, the Company contends that such tracking mechanisms are "not unusual." PGE/300, Niman-Hager/33. However, the information contained in Exhibit PGE/302 does not present the full story, and PGE's representations regarding

[2/] Staff stated that one of the "few exceptions" is when deferred accounting is appropriate to "to match appropriately the costs borne by and the benefits received by ratepayers" pursuant to ORS § 757.259(2)(e).

prior tracking mechanisms are somewhat misleading. Indeed, review of the various cost recovery mechanisms shown in Exhibit PGE/302 illustrates that the Commission has generally adopted such mechanisms only in significant or unusual circumstances and generally with the expectation they would be temporary. Overall, the history of these adjustments shows that the Commission has been reluctant to rely on cost recovery mechanisms as a permanent part of PGE's rate structure.

Q. WHAT DOES A MORE COMPLETE REVIEW OF THE ORDERS CITED IN EXHIBIT PGE/302 REVEAL ABOUT THE USE OF TRACKING MECHANISMS IN THE PAST?

A. I believe it is useful to understand a more complete history of the various mechanisms cited in Exhibit PGE/302. First, it should be noted that a comprehensive "PCA," as it is currently understood, has rarely been utilized in the past. In this context, I am referring to a PCA that adjusts all types of power costs and has a mechanism for true-up to actual. The only comprehensive PCA mechanisms authorized by the Commission for PGE were the nine and fifteen month PCAs in 2001 and 2002. Thus, over the past thirty years, comprehensive PCAs were only in effect for two years. These PCAs were the result of the Stipulation Concerning Power Costs in UE 115 and were not implemented over the objections of Staff or intervenors.

Finally, review of the Commission orders shows that although the Commission has allowed temporary surcharges designed to mitigate extreme hydro deficits, the Commission has never approved of a permanent hydro tracking mechanism as proposed in this case. This provides a compelling argument against implementation of the HGA because the Commission has a history of allowing cost recovery between rate cases only when warranted by truly extraordinary circumstances.

Q. PLEASE RELATE THE CIRCUMSTANCES SURROUNDING THE 1974 EXCESS COST OF POWER PROVISION.

A. This was a surcharge that only applied if power costs exceeded a specific threshold and was only in effect for five months before the Commission terminated it.

On March 24, 1974, PGE filed a general rate case, including a provision for automatic adjustments in billings in the event that average power costs exceeded 5 mills per kWh. Re PGE, OPUC Docket No. UF 3091, Order No. 74-657 at 1 (Sept. 3, 1974). The Commission concluded that an excess cost of power provision would give PGE some guarantee that, "if it is forced to incur additional costs, as a result of bad weather conditions and increased consumption, it can recover same, and yet protect the ratepayer if these conditions do not materialize." Id. at 4. On September 3, 1974, PGE was thus allowed to assess a monthly 2 mill per each kWh surcharge on all bills to recover any power costs in excess of 4.8 mills per kWh. Id. at 7. The Commission initially authorized this surcharge for the period September 1, 1974, through February 28, 1975. Id.

On December 31, 1974, in Order No. 75-005, the Commission found that then-recent data showed "that there should be a reduction in the assessment to 1 mill per kWh on all billings made on or after January 6, 1975." Re PGE, OPUC Docket No. UF 3091, Order No. 75-005 (Dec. 31, 1974). On January 30, 1975, in Order No. 75-089, the Commission "reviewed the need for the remaining 1 mill assessment in light of the mild winter weather to date and continued conservation" and terminated the temporary surcharge effective February 4, 1975. Re PGE, OPUC Docket No. UF 3091, Order No. 75-089 (Jan. 30, 1975).

Q. PLEASE PROVIDE DETAILS CONCERNING THE 1977 SURCHARGE.

A. This again was a temporary, emergency measure apparently designed to address drought conditions. It was only in effect from September 1977 to November 1977.

On July 7, 1977, the Commission found that PGE would require additional special revenues to recoup power costs if drought conditions continued or worsened and authorized PGE to file a power cost surcharge to be applied by PGE only after September 1, 1977. Re PGE, OPUC Docket No. UF 3339, Order No. 77-456 at 8-9 (July 7, 1977). Pursuant to that Order, PGE filed for authorization to apply a surcharge of 2.2 mills per kWh to begin on September 1, 1977. On August 19, 1977, the Commission authorized PGE to implement the surcharge to recoup excess power costs incurred as a result of adverse hydro conditions during the period of September 1, 1977, to June 30, 1978, but to remain in effect only as required by adverse hydro conditions. Re PGE, OPUC Docket No. UF 3339, Order No. 77-559 at 1-2 (Aug. 19, 1977). On November 30, 1977, the Commission suspended the surcharge because it had generated revenues above the excess costs and hydro conditions had shown improvement. Re PGE, OPUC Docket No. UF 3339, Order No. 77-813 (Nov. 30, 1977).

Q. PLEASE PROVIDE A SUMMARY OF THE 1979-1987 PCA

This tracking mechanism was not intended as a tool for recovery of hydro variations, but rather was intended for recovery of extraordinary power costs, primarily due to increased prices for gas and oil resulting from the Iranian crisis of 1979. It was not a comprehensive PCA and it did not allow recovery of changes in nuclear or coal fuels. Further, it excluded increases for additional generation or purchased power beyond amounts specified in the preceding general rate order. In addition, there was a limit on the level of the adjustment (0.4 cents per kWh) and only 80% of excess power costs were recovered. Ultimately, the Commission terminated the PCA because it was no longer needed and to prevent potential abuse by PGE.

On June 1, 1979, PGE requested a PCA as part of its general rate case filing to allow the Company to recover from ratepayers 80% of extraordinary power costs associated with hydro variability, fuel costs, thermal plant efficiency, and cost of purchased power. Re PGE, OPUC Docket No. UF 3518, Order No. 79-830 at 1 (Nov. 15, 1979). Commissioner John Lobdell approved the PCA, apparently on the basis that it would track the increased gas and oil costs during this period; however, the actual scope of the PCA as implemented by PGE is somewhat uncertain. The order in which the PCA was initially approved is unclear in describing the scope of the mechanism, and it appears to allow for recovery of increases in the price of purchased power, but not changes in volume:

> Price increases for fuel used at the Beaver, Harborton, Summit, and Bethel facilities and for purchased power in excess of that adopted in the last general rate order are covered. Increases for

> additional generation or purchased power beyond amounts specified in the last general rate order are excluded.

Id. at 4-5. Nevertheless, in a subsequent order in which the PCA was reauthorized, Commissioner Lobdell stated that the PCA covered "only the effect of increased prices of oil and gas used to generate electricity" and noted that the price of oil and gas had doubled in one year at the time of PGE's initial request. Re PGE, OPUC Docket No. UF 3518, Order No. 80-021 at 4 (Jan. 14, 1980).

Q. DID THE 1979 ORDER PLACE LIMITS ON THE LEVEL OF THE PCA AND THE AMOUNT OF COSTS RECOVERED?

A. Yes. The Commission only allowed recovery of 80% of excess power costs and limited the PCA adjustment rate to 0.4 cents per kWh.

Q. WHAT HAPPENED NEXT?

A. On January 14, 1980, the Commission renewed authorization of the PCA in its general rate case order, but noted that unless the oil and natural gas prices increased dramatically, the unanticipated power costs should be fully recovered within six months and the PCA should be reduced to zero. Id. at 5. Further, the Commission ordered that in the event that oil or natural gas prices declined below the base rates established in the general rate order, 80% of the benefit would flow to PGE's customers. Id.

Following reauthorization of the PCA in 1980, the PCA was in effect for seven years. On September 30, 1987, the Commission found that the PCA should be eliminated because it was no longer needed. Re PGE, OPUC Docket Nos. UE 47, UE 48, Order No. 87-1017 at 33 (Sept. 30, 1987). The Commission noted that

PGE could absorb the anticipated increases in power costs and discussed at length its rationale for terminating the PCA:

> The Commission finds that the power-cost adjustment should be eliminated. The original need for the power-cost adjustment, volatility of power costs, no longer exists to the same degree as existed in 1979. PGE can absorb the anticipated increases in power costs. If it faces large unanticipated increases in costs or a reduction in sales for resale, it can request a rate increase. If PGE can lower its power costs or increase its sales for resale, it can keep the additional net income until the next rate adjustment.
>
> Furthermore, none of the other electric utilities regulated by the PUC have power-cost adjustment clauses. PGE's system characteristics are not so unique that a power-cost adjustment clause is necessary.
>
> Finally, elimination of the PCA will limit opportunities for abuse of the rate process. In Oregon, power cost adjustment changes have never been reviewed in public hearings. PGE could manipulate its earnings by failing to recognize its sales for resale in a particular PCA revision. The lack of public review creates an opportunity for mischief which cannot be tolerated.

Id. at 33-34.

Q. WHAT WERE THE CIRCUMSTANCES SURROUNDING THE MECHANISM IN PLACE DURING THE 1991-1994 PERIOD SHOWN ON EXHIBIT PGE/302?

A. Again, this was not a comprehensive PCA, nor was it a mechanism related to hydro deficits. This was a series of deferred accounts related to outages and the eventual shutdown of PGE's Trojan nuclear generating facility. A review of the Commission's orders regarding the Trojan deferrals reveals that the Commission authorized PGE to defer between 50% and 90% of its excess replacement power costs associated with the Trojan outage starting in 1991 and the eventual shutdown of the plant in 1994. Re PGE, OPUC Docket Nos. UE 81, UE 82, UM 445, UE 47, Order No. 97-1781 at 4 (Dec. 20, 1991); Re PGE, OPUC Docket No.

UM 529, Order No. 93-309 at 1 (Mar. 11, 1993); Re PGE, OPUC Docket Nos. UM 571, UM 594, Order No. 93-1493 at 2 (Oct. 15, 1993). Again, it appears that the Trojan outages and closure were essentially viewed as an "extreme circumstance." In authorizing the deferred account related to the first Trojan outage, the Commission specifically found that "Trojan provide[d] 24 percent of PGE's power, a higher percentage than any other single resource for an Oregon electric utility[,]" and concluded that ratepayers should bear some of the cost. OPUC Docket Nos. UE 81, UE 82, UM 445, UE 47, Order No. 97-1781 at 3.

Furthermore, in the course of deciding on this issue, the Commission specifically rejected a PGE request to recover its excess replacement power costs related to the Trojan outages through a more traditional PCA rather than a deferred account. The Commission concluded that allowing PGE to defer a certain percentage of its excess replacement power costs was more appropriate than implementing a PCA-like mechanism to track PGE's costs and implement periodic rate changes. Id. Rather than providing support for the use of PCAs, the Commission's orders regarding the Trojan deferrals actually demonstrate that the Commission is reluctant to adopt such mechanisms.

Q. WHAT WERE THE CIRCUMSTANCES SURROUNDING THE 2001 AND 2002 PCAs?

A. These were the only comprehensive PCA type mechanisms in place for PGE and both were the result of a settlement agreement. The primary reason for allowing these PCAs was to afford PGE relief from the Western power crisis.

On December 28, 2000, Commission Staff filed an application for deferral of a portion of PGE's excess net variable power costs from January 1, 2001, through September 30, 2001. On January 11, 2001, PGE filed a similar application to defer all changes in its net variable power costs from January 11, 2001, through December 31, 2001. Following a series of settlement conferences, PGE, Staff, the Citizens' Utility Board ("CUB"), Fred Meyer Stores, and ICNU reached an agreement allowing PGE to defer 100% of all changes in PGE's net variable power costs incurred as a result of the volatile wholesale market from January 1, 2001, through September 30, 2001. Re PGE, OPUC Docket Nos. UM 1008, UM 1009, Order No. 01-231 (Mar. 14, 2001). All parties also agreed to recommend the Commission allow only a specified portion of the deferral, in accordance with a stipulated deadband, to be recovered or refunded in future customer rates. If the deferred amount was $35 million above or below the Baseline Net Variable Power Costs (the "Baseline"), PGE would not amortize any amount. If the variance from the Baseline was between $35 million and $56 million, 50% of the variance would be shared between customers and the Company. If the variance from the Baseline exceeded $56 million, the customers would be charged, or credited, 90% of the costs. On January 24, 2002, PGE filed an application to implement tariff schedules to allow PGE to amortize approximately $90 million, offset by certain customer credits, as approved in Order No. 01-231. The Commission approved PGE's application for amortization on March 28, 2002. Re PGE, OPUC Docket No. UE 136, Order No. 02-215 (Mar. 28, 2002).

On July 27, 2001, PGE, Staff, ICNU, CUB, and Fred Meyer filed the Stipulation Concerning Power Costs in Docket No. UE 115, resolving all power cost issues, including establishing a PCA by which PGE could account for variations between expected power costs included in base rates and actual power costs incurred between October 2001 and December 2002. The stipulation was adopted by the Commission on August 31, 2001. Re PGE, OPUC Docket No. UE 115, Order No. 01-777 (Aug. 31, 2001). The PCA was only approved to be effective for a period of 15 months and terminated on December 31, 2002.

Q. GIVEN THIS MORE DETAILED BACKGROUND INFORMATION, PLEASE SUMMARIZE YOUR CONCLUSIONS REGARDING PGE'S CHARACTERIZATION OF OPUC PRECEDENT REGARDING PCAs.

A. I believe that PGE has failed to accurately portray all of the facts and circumstances concerning these items. First, it is apparent that the Commission has never adopted a permanent hydro tracking mechanism such as the HGA, and it has only allowed a PCA to be in effect for a brief period of time during the 30 year period. Also, the Commission has authorized deferred accounting or surcharges when warranted by extraordinary conditions rather than approving ongoing PCA-type mechanisms to track normal cost variations. In addition, the Commission has often allowed only a portion of these excess costs to be recovered. Finally, there is ample evidence to demonstrate that the regulatory process has allowed PGE to recover some extraordinary costs in extreme circumstances. Thus, PGE's complaint that it could suffer severe impacts due to poor hydro conditions is unfounded because the Commission has acted in the past to address serious problems when they occurred. Ultimately, it is incorrect and misleading to assert that a PCA or other type of power cost tracking mechanism has been an ordinary and usual feature of PGE's regulatory history. Rather, such mechanisms have largely been limited to specific items in extreme circumstances.

Transparency

Q. MS. LESH CONTENDS THAT "TRANSPARENCY" IS ONE OF THE ADVANTAGES OF THE HGA PROPOSAL. DO YOU AGREE?

A. Ms. Lesh suggests that the HGA mechanism is not complex, and thus fosters the goal of "transparency" or administrative ease. However, PGE's rates are already too complex, with too many riders and adjustment clauses, even without the HGA. The HGA is a step in the "wrong direction" because it would further complicate an already complicated rate structure. Based on PGE's January 1, 2005 price summary sheet (obtained from the PGE website), the Company's rate schedules already contain the following adjustment clauses or other special riders:

Schedule 101 Energy Efficiency Adjustment
Schedule 102 BPA Subscription Power Credit
Schedule 105 Regulatory Adjustments
Schedule 107 DSM Investment Financing Adjustment
Schedule 108 Public Purpose Charge
Schedule 114 FAS 109 Adjustment (FAS Statement 109 Taxes)
Schedule 115 Low-Income Assistance
Schedule 125 Resource Valuation Mechanism
Schedule 126 Power Cost Adjustment (Deferral Recovery)
Schedule 129 Five Year Transition Cost Adjustment
Schedule 130 Shopping Incentive Adjustment Part

I am most familiar with the RVM (Schedule 125). Schedule 125 actually has multiple parts and is extremely complex. In UE 161, the Company informed ICNU that revising the rates computed under Schedule 125 was quite time consuming and would take the Company a week or more to complete. Certainly, some of the other items listed above are also quite complex. This rate schedule complexity makes it quite difficult for consumers to understand their rates and more difficult for the Commission to regulate them. This is another reason why the Commission should not further complicate PGE's rate schedules by adopting the HGA. Indeed, a better procedure would be to eliminate as many of the above Schedules as possible in the next rate case. This provides yet one more reason why the HGA should not be considered outside of the context of a new general rate case.

Estimated Impact of the HGA

Q. DO YOU HAVE ANY COMMENTS ON EXHIBIT PGE/702, PRESENTED IN MR. KUNS' TESTIMONY?

A. Yes. In this analysis, Mr. Kuns purports to present a "back-cast" of the HGA tariff had it been implemented in 1990. While the Company presents no true impact analysis of the HGA, this analysis is intended to illustrate how it would have worked over the recent fourteen-year period.

Mr. Kuns' example appears to show that ratepayers would have benefited from the HGA, receiving substantial credits over the period, and that power costs would have been $45 million less than without a HGA.

However, Mr. Kuns' example is misleading, in that it assumes there is no relationship between the average market price for energy and hydro energy available to PGE. This is rather ironic considering that PGE justifies its request on the basis of the asymmetric impact of hydro availability on cost (i.e., the assumption that poor hydro conditions tend to increase costs and prices more than good hydro conditions reduce costs and prices). If the Commission is swayed by PGE's examples of the relationship between hydro generation and power costs shown in Exhibit PGE/301, then it should not accept Exhibit PGE/702 as a fair representation of the impact of the HGA.

Q. HAVE YOU RECOMPUTED EXHIBIT PGE/702 USING THE ASSUMPTIONS FROM EXHIBIT PGE/301?

A. Yes. Exhibit ICNU/104 shows the results of this analysis assuming the "strong" relationship between market prices and hydro energy described by PGE. On the basis of these assumptions, ratepayers would have incurred substantially higher costs for power ($143 million) than if no HGA had been implemented. Overall, the HGA results in a cost increase (and ultimately corresponding rate increases) of $10 million per year. This illustrates that the PGE proposal is not revenue neutral and that the HGA is most certainly not "symmetrically designed."

Q. HAVE YOU PERFORMED A LONGER-TERM BACK-CAST?

A. Yes. This is shown on Exhibit ICNU/105. Over the period 1929 to 2003, under the "strong" market price assumptions, ratepayers would on average incur approximately $9 million more per year due to the HGA.

<u>Alternatives to the HGA</u>

Q. ASSUMING THE COMMISSION WISHES TO IMPLEMENT SOME SORT OF HYDRO MECHANISM IN THIS CASE, RATHER THAN WAITING FOR A NEW GENERAL RATE CASE, WHAT DO YOU RECOMMEND?

A. In that case, I would recommend implementation of a "hydro hedge" tariff to simulate a hypothetical hedge agreement between PGE and ratepayers. The concept is that ratepayers would be the counterparty to a hedge (much like Aquila was for PacifiCorp in their hedge arrangement).

Under this proposal, ratepayers would compensate PGE for a specific dollar amount in the event of poor hydro conditions. The hedge would only be implemented if hydro conditions substantially departed from normal or average conditions. For example, if hydro conditions were in the 10th percentile (i.e. 90% of all expected hydro conditions would be better) ratepayers would pay the Company (via the tariff) an amount equal to the expected cost of replacement energy based on market price forecasts used in RVM. Likewise, when hydro conditions were in the 90th percentile (i.e. more water than 90% of all prior years), ratepayers would be paid via a credit in the tariff.

Payment and credit charges might not be equal. For the tariff to be revenue neutral, it may have to have an unbalanced schedule of payments and credit. The hedge would not necessarily be "symmetric" in the sense that it would pay ratepayers the same amount as PGE is paid, or that the thresholds would be equal.

One serious problem with properly designing such a hedge is that it is necessary to have a good approximation of the relationship between hydro generation and market prices. Without such information, it would be very difficult to design a truly revenue-neutral hedge. Thus, the lack of appropriate modeling seriously handicaps this approach at the present time.

Q. IS IT POSSIBLE TO DEVELOP EXAMPLE HEDGES BASED ON PGE'S EXHIBITS PGE/702 AND PGE/301?

A. Yes, however, I again caution the Commission to recognize that there is no empirical data to support the figures used in Exhibit PGE/301.

Assuming that market prices stay flat at the $40.97/MWh used in Mr. Kuns' Exhibit PGE/702, it would not be difficult to design a revenue neutral hedge. For example, payments and credits would be approximately equal if the payment and credit thresholds were set at the 12th and 89th percentiles respectively. See ICNU/106, Falkenberg/1-2.

However, assuming that the "strong" market price/hydro generation relationship prevailed, it would be quite difficult to make the hedge revenue neutral. For example, if the payment threshold were set at the 12th percentile, then PGE would expect to collect (over seventy five years, the period of time of the hydro data) $8.02 million. Even if credits started in the 48th percentile,[3] ratepayers would only expect to receive credits totaling $6.50 million.

It would be possible to solve this problem by requiring PGE to pay a premium of approximately $1.52 million every year to ratepayers ($8.02 million - $6.50 million).

Q. IS A PREMIUM OF THIS SORT A REASONABLE FEATURE OF THIS HYPOTHETICAL "HYDRO HEDGE" TARIFF?

A. Certainly. Even if a premium were not needed to assure revenue neutrality, PGE should normally expect to pay a counterparty to enter into a hedge. For example, PacifiCorp paid Aquila $1.75 million per year as a premium to enter into a hydro hedge. I see no reason why ratepayers should assume the risks of a hedge arrangement, but not be afforded a fair premium for doing so.

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[3] This is the point at which the hydro conditions start to exceed the 75 year average.

Q. PGE INDICATED IN ITS RESPONSE TO ICNU DR NO. 1.16 THAT IT ONLY WOULD CONSIDER HEDGES THAT WERE TIED TO ACTUAL MARKET PRICES. ICNU/107, FALKENBERG/1. WOULD THE ICNU ALTERNATIVE USE ACTUAL MARKET PRICES OR A FORECAST?

A. It would be impossible to assure revenue neutrality if actual market prices were used. In addition, use of actual market price would make a hydro hedge a "blank check" for either the Company or ratepayers. I am fearful that if ratepayers were due a very large credit, PGE might file to do away with the tariff using some variant of Ms. Lesh's "deep pockets" argument. It is worth noting that according to PGE's response to ICNU DR No. 1.15, PGE was apparently unable to arrange a hydro hedge with counterparties due to its insistence that actual market prices be used to compute the payments or credit. ICNU/108, Falkenberg/1-2. Apparently, rational counterparties were unwilling to assume unbounded risks. Ratepayers should not be required to do so either.

Retroactive Application of the HGA or an Alternative Mechanism

Q. ARE YOU FAMILIAR WITH PGE'S APPLICATION FOR DEFERRED ACCOUNTING RELATED TO THE HGA?

A. Yes. On December 30, 2004, PGE filed an Application for Deferral of Costs and Benefits due to Hydro Generation Variance in Docket No. UM 1187. In this Application, PGE stated that it was making "this request to preserve the positive or negative variance in the Deferral Period for treatment either under Schedule 128, or in some other manner as decided by the Commission in this docket or docket UE 165." Re PGE, OPUC Docket No. UM 1187, Application for Deferral of Costs and Benefits due to Hydro Generation Variance at 1 (Dec. 30, 2004). On January 21, 2005, PGE filed an amendment to its Application stating that the

Company was "requesting that the Commission approve th[e] Application irrespective of the ultimate outcome in UE 165." Re PGE, OPUC Docket No. UM 1187, Amendment to Application for Deferral of Costs and Benefits due to Hydro Generation Variance at 1 (Jan. 21, 2005).

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO PGE'S APPLICATION FOR DEFERRED ACCOUNTING AS IT RELATES TO THE HGA AT ISSUE IN THIS DOCKET?

A. PGE filed its deferred accounting Application in UM 1187 in part to gain approval of the HGA "retroactively" back to the date of the Application. According to PGE, "[i]f Schedule 128 is approved, then amounts deferred under this Application will simply become part of the hydro generation balancing account under the terms of Schedule 128." Id.

I recommend that the Commission deny the HGA altogether for all of the reasons described in this testimony. However, even if the Commission approves the HGA or some alternative mechanism in this Docket, I recommend that the Commission deny PGE's request to apply that mechanism retroactively. Granting retroactive approval of the HGA would constitute poor public policy by charging customers for costs incurred prior to approval of the tariff. This would deviate from the prospective basis on which the Commission typically approves utility rates. PGE has not justified retroactive application of the HGA or any other mechanism.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

ICNU/101

Randall J. Falkenberg Qualifications

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

EDUCATIONAL BACKGROUND

I received my Bachelor of Science degree with Honors in Physics and a minor in mathematics from Indiana University. I received a Master of Science degree in Physics from the University of Minnesota. My thesis research was in nuclear theory. At Minnesota I also did graduate work in engineering economics and econometrics. I have completed advanced study in power system reliability analysis.

PROFESSIONAL EXPERIENCE

After graduating from the University of Minnesota in 1977, I was employed by Minnesota Power as a Rate Engineer. I designed and coordinated the Company's first load research program. I also performed load studies used in cost-of-service studies and assisted in rate design activities.

In 1978, I accepted the position of Research Analyst in the Marketing and Rates department of Puget Sound Power and Light Company. In that position, I prepared the two-year sales and revenue forecasts used in the Company's budgeting activities and developed methods to perform both near- and long-term load forecasting studies.

In 1979, I accepted the position of Consultant in the Utility Rate Department of Ebasco Service Inc. In 1980, I was promoted to Senior Consultant in the Energy Management Services Department. At Ebasco I performed and assisted in numerous studies in the areas of cost of service, load research, and utility planning. In particular, I was involved in studies concerning analysis of excess capacity, evaluation of the planning activities of a major utility on behalf of its public service commission, development of a methodology for computing avoided costs and cogeneration rates, long-term electricity price forecasts, and cost allocation studies.

At Ebasco, I specialized in the development of computer models used to simulate utility production costs, system reliability, and load patterns. I was the principal author of production costing software used by eighteen utility clients and public service commissions for evaluation of marginal costs, avoided costs and production costing analysis. I assisted over a dozen utilities in the performance of marginal and avoided cost studies related to the PURPA of 1978. In this capacity, I worked with utility planners and rate specialists in quantifying the rate and cost impact of generation expansion alternatives. This activity included estimating carrying costs, O&M expenses, and capital cost estimates for future generation.

In 1982 I accepted the position of Senior Consultant with Energy Management Associates, Inc. and was promoted to Lead Consultant in June 1983. At EMA I trained and consulted with planners and financial analysts at several

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

utilities in applications of the PROMOD and PROSCREEN planning models. I assisted planners in applications of these models to the preparation of studies evaluating the revenue requirements and financial impact of generation expansion alternatives, alternate load growth patterns and alternate regulatory treatments of new baseload generation. I also assisted in EMA's educational seminars where utility personnel were trained in aspects of production cost modeling and other modern techniques of generation planning.

I became a Principal in Kennedy and Associates in 1984. Since then I have performed numerous economic studies and analyses of the expansion plans of several utilities. I have testified on several occasions regarding plant cancellation, power system reliability, phase-in of new generating plants, and the proper rate treatment of new generating capacity. In addition, I have been involved in many projects over the past several years concerning the modeling of market prices in various regional power markets.

In January 2000, I founded RFI Consulting, Inc. whose practice is comparable to that of my former firm, J. Kennedy and Associates, Inc.

The testimony that I present is based on widely accepted industry standard techniques and methodologies, and unless otherwise noted relies upon information obtained in discovery or other publicly available information sources of the type frequently cited and relied upon by electric utility industry experts. All of the analyses that I perform are consistent with my education, training and experience in the utility industry. Should the source of any information presented in my testimony be unclear to the reader, it will be provided it upon request by calling me at 770-379-0505.

PAPERS AND PRESENTATIONS

Mid-America Regulatory Commissioners Conference - June 1984: "Nuclear Plant Rate Shock - Is Phase-In the Answer"

Electric Consumers Resource Council - Annual Seminar, September 1986: "Rate Shock, Excess Capacity and Phase-in"

The Metallurgical Society - Annual Convention, February 1987: "The Impact of Electric Pricing Trends on the Aluminum Industry"

Public Utilities Fortnightly - "Future Electricity Supply Adequacy: The Sky Is Not Falling" What Others Think, January 5, 1989 Issue

Public Utilities Fortnightly - "PoolCo and Market Dominance", December 1995 Issue

QUALIFICATIONS OF RANDALL J. FALKENBERG, PRESIDENT

APPEARANCES

3/84	8924	KY	Airco Carbide	Louisville Gas & Electric	CWIP in rate base.
5/84	830470-EI	FL	Florida Industrial Power Users Group	Fla. Power Corp.	Phase-in of coal unit, fuel savings basis, cost allocation.
10/84	89-07-R	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power	Excess capacity.
11/84	R-842651	PA	Lehigh Valley Power Committee	Pennsylvania Power & Light Co.	Phase-in of nuclear unit.
2/85 cancellation of	I-840381	PA	Phila. Area Ind. Energy Users' Group	Electric Co.	Philadelphia Economics of nuclear generating units.
3/85 fossil	Case No. 9243	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Economics of cancelling generating units.
3/85 storage	R-842632	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Economics of pumped generating units, optimal res. margin, excess capacity.
3/85	3498-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear unit cancellation, load and energy forecasting, generation economics.
5/85	84-768-E-42T	WV	West Virginia Multiple Intervenors	Monongahela Power Co.	Economics - pumped storage generating units, reserve margin, excess capacity.
7/85	E-7, SUB 391	NC	Carolina Industrial Group for Fair Utility Rates	Duke Power Co.	Nuclear economics, fuel cost projections.
7/85	9299	KY	Kentucky Industrial Utility Consumers	Union Light, Heat & Power Co.	Interruptible rate design.
8/85	84-249-U	AR	Arkansas Electric Energy Consumers	Arkansas Power & Light Co.	Prudence review.
1/86	85-09-12	CT	Connecticut Ind. Energy Consumers	Connecticut Light & Power Co.	Excess capacity, financial impact of phase-in nuclear plant.
1/86	R-850152	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Phase-in and economics of nuclear plant.
2/86	R-850220	PA	West Penn Power Industrial Intervenors	West Penn Power	Optimal reserve margins, prudence, off-system sales guarantee plan.
5/86	86-081-E-GI	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Generation planning study , economics prudence of a pumped storage hydroelectric unit.
5/86	3554-U	GA	Attorney General &	Georgia Power Co.	Cancellation of nuclear

**Expert Testimony Appearances
of
Randall J. Falkenberg**

Date	Case	Jurisdict.	Party	Utility	Subject
			Georgia Public Service Commission Staff		plant.
9/86	29327/28	NY	Occidental Chemical Corp.	Niagara Mohawk Power Co.	Avoided cost, production cost models.
9/86	E7- Sub 408	NC	NC Industrial Energy Committee	Duke Power Co.	Incentive fuel adjustment clause.
12/86 613	9437/	KY	Attorney General of Kentucky	Big Rivers Elect. Corp.	Power system reliability analysis, rate treatment of excess capacity.
5/87	86-524- E-SC	WV	West Virginia Energy Users' Group	Monongahela Power	Economics and rate treatment of Bath County pumped storage County Pumped Storage Plant.
6/87	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
6/87	PUC-87- 013-RD E002/E-015 -PA-86-722	MN	Eveleth Mines & USX Corp.	Minnesota Power/ Northern States	Sale of generating unit and reliability Power requirements.
7/87	Docket 9885	KY	Attorney General of Kentucky	Big Rivers Elec. Corp.	Financial workout plan for Big Rivers.
8/87	3673-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Nuclear plant prudence audit, Vogtle buyback expenses.
10/87	R-850220	PA	WPP Industrial Intervenors	West Penn Power	Need for power and economics, County Pumped Storage Plant
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Cost allocation methods and interruptible rate design.
10/87	870220-EI	FL	Occidental Chemical	Fla. Power Corp.	Nuclear plant performance.
1/88	Case No. 9934	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Review of the current status of Trimble County Unit 1.
3/88	870189-EI	FL	Occidental Chemical Corp.	Fla. Power Corp.	Methodology for evaluating interruptible load.
5/88	Case No. 10217	KY	National Southwire Aluminum Co., ALCAN Alum Co.	Big Rivers Elec. Corp.	Debt restructuring agreement.
7/88	Case No. 325224	LA Div. I 19th Judicial District	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend Nuclear Plant.
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization gas sales and revenues.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/88 gas	3799-U	GA	Georgia Public Service Commission Staff	United Cities Gas Co.	Weather normalization of sales and revenues.
12/88	88-171-EL-AIR 88-170-EL-AIR	OH OH	Ohio Industrial Energy Consumers	Toledo Edison Co., Cleveland Electric Illuminating Co.	Power system reliability reserve margin.
1/89	I-880052	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Nuclear plant outage, replacement fuel cost recovery.
2/89	10300	KY	Green River Steel K	Kentucky Util.	Contract termination clause and interruptible rates.
3/89	P-870216 283/284/286	PA	Armco Advanced Materials Corp., Allegheny Ludlum Corp.	West Penn Power	Reserve margin, avoided costs.
5/89	3741-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Prudence of fuel procurement.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Need and economics coal & nuclear capacity, power system planning.
10/89	2087	NM	Attorney General of New Mexico	Public Service Co. of New Mexico	Power system planning, economic and reliability analysis, nuclear planning, prudence.
10/89	89-128-U	AR	Arkansas Electric Energy Consumers	Arkansas Power Light Co.	Economic impact of asset transfer and stipulation and settlement agreement.
11/89	R-891364	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	Sale/leaseback nuclear plant, excess capacity, phase-in delay imprudence.
1/90	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Sale/leaseback nuclear power plant.
4/90	89-1001-EL-AIR	OH	Industrial Energy Consumers	Ohio Edison Co.	Power supply reliability, excess capacity adjustment.
4/90	N/A	N.O.	New Orleans Business Counsel	New Orleans Public Service Co.	Municipalization of investor-owned utility, generation planning & reliability
7/90	3723-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Weather normalization adjustment rider.
9/90	8278	MD	Maryland Industrial Group	Baltimore Gas & Electric Co.	Revenue requirements gas & electric, CWIP in rate base.
9/90	90-158	KY	Kentucky Industrial Utility Consumers	Louisville Gas & Electric Co.	Power system planning study.
12/90	U-9346	MI	Association of	Consumers Power	DSM Policy Issues.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Businesses Advocating Tariff Equity (ABATE)		
5/91	3979-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	DSM, load forecasting and IRP.
7/91	9945	TX	Office of Public Utility Counsel	El Paso Electric Co.	Power system planning, quantification of damages of imprudence, environmental cost of electricity
8/91	4007-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Integrated resource planning, regulatory risk assessment.
11/91	10200	TX	Office of Public	Texas-New Mexico Utility Counsel	Imprudence disallowance. Power Co.
12/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Year-end sales and customer adjustment, jurisdictional allocation.
1/92	89-783-E-C	WVA	West Virginia Energy Users Group	Monongahela Power Co.	Avoided cost, reserve margin, power plant economics.
3/92	91-370	KY	Newport Steel Co.	Union Light, Heat & Power Co.	Interruptible rates, design, cost allocation.
5/92	91890	FL	Occidental Chemical Corp.	Fla. Power Corp.	Incentive regulation, jurisdictional separation, interruptible rate design.
6/92	4131-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Integrated resource planning, DSM.
9/92	920324	FL	Florida Industrial Power Users Group	Tampa Electric Co.	Cost allocation, interruptible rates decoupling and DSM.
10/92	4132-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Residential conservation program certification.
10/92	11000	TX	Office of Public Utility Counsel	Houston Lighting and Power Co.	Certification of utility cogeneration project.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Direct)	Production cost savings from merger.
11/92	8469	MD	Westvaco Corp.	Potomac Edison Co.	Cost allocation, revenue distribution.
11/92	920606	FL	Florida Industrial Power Users Group	Statewide Rulemaking	Decoupling, demand-side management, conservation, Performance incentives.
12/92	R-009 22378	PA	Armco Advanced Materials	West Penn Power	Energy allocation of production costs.
1/93	8179	MD	Eastalco Aluminum/ Westvaco Corp.	Potomac Edison Co.	Economics of QF vs. combined cycle power plant.
2/93	92-E-0814 88-E-081	NY	Occidental Chemical Corp.	Niagara Mohawk Power Corp.	Special rates, wheeling.

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
3/93	U-19904	LA	Louisiana Public Service Commission Staff	Entergy/Gulf States Utilities (Surrebuttal)	Production cost savings from merger.
4/93	EC92 21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities/Entergy	GSU Merger prodcution cost savings
6/93	930055-EU	FL	Florida Industrial Power Users' Group	Statewide Rulemaking	Stockholder incentives for off-system sales.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers & Attorney General	Big Rivers Elec. Corp.	Prudence of fuel procurement decisions.
9/93	4152-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co.	Cost allocation of pollution control equipment.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minn. Power Co.	Analysis of revenue req. and cost allocation issues.
4/94	93-465	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Review and critique proposed environmental surcharge.
4/94	4895-U	GA	Georgia Textile Manufacturers Assn.	Georgia Power Co	Purchased power agreement and fuel adjustment clause.
4/94	E-015/ GR-94-001	MN	Large Power Intervenors	Minnesota Power Light Co.	Rev. requirements, incentive compensation.
7/94	94-0035-E-42T	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue annualization, ROE performance bonus, and cost allocation.
8/94	8652	MD	Westvaco Corp.	Potomac Edison Co.	Revenue requirements, ROE performance bonus, and revenue distribution.
1/95	94-332	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Environmental surcharge.
1/95	94-996-EL-AIR	OH	Industrial Energy Users of Ohio	Ohio Power Company	Cost-of-service, rate design, demand allocation of power
3/95	E999-CI	MN	Large Power Intervenor	Minnesota Public Utilities Comm.	Environmental Costs Of electricity
4/95	95-060	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Company	Six month review of CAAA surcharge.
11/95	I-940032	PA	The Industrial Energy Consumers of Pennsylvania	Statewide - all utilities	Direct Access vs. Poolco, market power.
11/95	95-455	KY	Kentucky Industrial	Kentucky Utilities	Clean Air Act Surcharge,
12/95	95-455	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Company	Clean Air Act Compliance Surcharge.
6/96	960409-EI	FL	Florida Industrial	Tampa Electric Co.	Polk County Power Plant

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
			Power Users Group		Rate Treatment Issues.
3/97	R-973877	PA	PAIEUG.	PECO Energy	Stranded Costs & Market Prices.
3/97	970096-EQ	FL	FIPUG	Fla. Power Corp.	Buyout of QF Contract
6/97	R-973593	PA	PAIEUG	PECO Energy	Market Prices, Stranded Cost
7/97	R-973594	PA	PPLICA	PP&L	Market Prices, Stranded Cost
8/97	96-360-U	AR	AEEC	Entergy Ark. Inc.	Market Prices and Stranded Costs, Cost Allocation, Rate Design
10/97	6739-U	GA	GPSC Staff	Georgia Power	Planning Prudence of Pumped Storage Power Plant
10/97	R-974008 R-974009	PA	MIEUG PICA	Metropolitan Ed. PENELEC	Market Prices, Stranded Costs
11/97	R-973981	PA	WPII	West Penn Power	Market Prices, Stranded Costs
11/97	R-974104	PA	DII	Duquesne Light Co.	Market Prices, Stranded Costs
2/98	APSC 97451 97452 97454	AR	AEEC	Generic Docket	Regulated vs. Market Rates, Rate Unbundling, Timetable for Competition.
7/98	APSC 87-166	AR	AEEC	Entergy Ark. Inc.	Nuclear decommissioning cost estimates & rate treatment.
9/98	97-035-01	UT	DPS and CCS	PacifiCorp	Net Power Cost Stipulation, Production Cost Model Audit
12/98	19270	TX	OPC	HL&P	Reliability, Load Forecasting
4/99	19512	TX	OPC	SPS	Fuel Reconciliation
4/99	99-02-05	CT	CIEC	CL&P	Stranded Costs, Market Prices
4/99	99-03-04	CT	CIEC	UI	Stranded Costs, Market Prices
6/99	20290	TX	OPC	CP&L	Fuel Reconciliation
7/99	99-03-36	CT	CIEC	CL&P	Interim Nuclear Recovery
7/99	98-0453	WV	WVEUG	AEP & APS	Stranded Costs, Market Prices
12/99	21111	TX	OPC	EGSI	Fuel Reconciliation
2/00	99-035-01	UT	CCS	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
5/00	99-1658	OH	AK Steel	CG&E	Stranded Costs, Market Prices
6/00	UE-111	OR	ICNU	PacifiCorp	Net Power Costs, Production Cost Modeling Issues
9/00	22355	TX	OPC	Reliant Energy	Stranded cost

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
10/00	22350	TX	OPC	TXU Electric	Stranded cost
10/00	99-263-U	AR	Tyson Foods	SW Elec. Coop	Cost of Service
12/00	99-250-U	AR	Tyson Foods	Ozarks Elec. Coop	Cost of Service
01/01	00-099-U	AR	Tyson Foods	SWEPCO	Rate Unbundling
02/01	99-255-U	AR	Tyson Foods	Ark. Valley Coop	Rate Unbundling
03/01	UE-116	OR	ICNU	PacifiCorp	Net Power Costs
6/01	01-035-01	UT	DPS and CCS	PacifiCorp	Net Power Costs
7/01	A.01-03-026	CA	Roseburg FP	PacifiCorp	Net Power Costs
7/01	23550	TX	OPC	EGSI	Fuel Reconciliation
7/01	23950	TX	OPC	Reliant Energy	Price to beat fuel factor
8/01	24195	TX	OPC	CP&L	Price to beat fuel factor
8/01	24335	TX	OPC	WTU	Price to beat fuel factor
9/01	24449	TX	OPC	SWEPCO	Price to beat fuel factor
10/01	20000-EP 01-167	WY	WIEC	PacifiCorp	Power Cost Adjustment Excess Power Costs
2/02	UM-995	OR	ICNU	PacifiCorp	Cost of Hydro Deficit
2/02	00-01-37	UT	CCS	PacifiCorp	Certification of Peaking Plant
4/02	00-035-23	UT	CCS	PacifiCorp	Cost of Plant Outage, Excess Power Cost Stipulation.
4/02	01-084/296	AR	AEEC	Entergy Arkansas	Recovery of Ice Storm Costs
5/02	25802	TX	OPC	TXU Energy	Escalation of Fuel Factor
5/02	25840	TX	OPC	Reliant Energy	Escalation of Fuel Factor
5/02	25873	TX	OPC	Mutual Energy CPL	Escalation of Fuel Factor
5/02	25874	TX	OPC	Mutual Energy WTU	Escalation of Fuel Factor
5/02	25885	TX	OPC	First Choice	Escalation of Fuel Factor
7/02	UE-139	OR	ICNU	Portland General	Power Cost Modeling
8/02	UE-137	OP	ICNU	Portland General	Power Cost Adjustment Clause
10/02	RPU-02-03	IA	Maytag, et al	Interstate P&L	Hourly Cost of Service Model
11/02	20000-Er 02-184	WY	WIEC	PacifiCorp	Net Power Costs, Deferred Excess Power Cost
12/02	26933	TX	OPC	Reliant Energy	Escalation of Fuel Factor
12/02	26195	TX	OPC	Centerpoint Energy	Fuel Reconciliation
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	UE-134	OR	ICNU	PacifiCorp	West Valley CT Lease payment

Expert Testimony Appearances
of
Randall J. Falkenberg

Date	Case	Jurisdict.	Party	Utility	Subject
1/03	27167	TX	OPC	First Choice	Escalation of Fuel Factor
1/03	26186	TX	OPC	SPS	Fuel Reconciliation
2/03	UE-02417	WA	ICNU	PacifiCorp	Rate Plan Stipulation, Deferred Power Costs
2/03	27320	TX	OPC	Reliant Energy	Escalation of Fuel Factor
2/03	27281	TX	OPC	TXU Energy	Escalation of Fuel Factor
2/03	27376	TX	OPC	CPL Retail Energy	Escalation of Fuel Factor
2/03	27377	TX	OPC	WTU Retail Energy	Escalation of Fuel Factor
3/03	27390	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27511	TX	OPC	First Choice	Escalation of Fuel Factor
4/03	27035	TX	OPC	AEP Texas Central	Fuel Reconciliation
05/03	03-028-U	AR	AEEC	Entergy Ark., Inc.	Power Sales Transaction
7/03	UE-149	OR	ICNU	Portland General	Power Cost Modeling
8/03	28191	TX	OPC	TXU Energy	Escalation of Fuel Factor
11/03	20000-ER -03-198	WY	WIEC	PacifiCorp	Net Power Costs
2/04	03-035-29	UT	CCS	PacifiCorp	Certification of CCCT Power Plant, RFP and Bid Evaluation
6/04	29526	TX	OPC	Centerpoint	Stranded cost true-up.
6/04	UE-161	OR	ICNU	Portland General	Power Cost Modeling
7/04	UE-032065	WA	ICNU	PacifiCorp	Power Cost modeling, Jurisdictional Allocation
7/04	UM-1050	OR	ICNU	PacifiCorp	Jurisdictional Allocation
10/04	15392-U 15392-U	GA	Calpine	Georgia Power/ SEPCO	Fair Market Value of Combined Cycle Power Plant
12/04	04-035-42	UT	CCS	PacifiCorp	Net power costs

ICNU/102

PGE Response to ICNU Data Request No. 1.14

December 29, 2004

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 1.14
Dated December 10, 2004
Question 014

Request:

Questions Related to the testimony of Pamela Lesh:

Does PGE track its market purchases to determine whether it systematically purchases power in the market at prices lower than or higher than the various published indices? If so, provide.

Response:
PGE objects to this request, as it is unclear to what part of the Pamela Lesh testimony, (PGE Exhibit 100), the question refers. Nevertheless, without waving objection, PGE responds as follows:

PGE has not performed any studies to determine whether we systematically purchase power at prices above or below any published index.

ICNU/103

PGE Response to ICNU Data Request No. 1.20

December 29, 2004

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 1.20
Dated December 10, 2004
Question 020

Request:

Questions Related to the testimony of Dr. Makholm:

Can Dr. Makholm quantify or at least approximate the ROE impact of PGE's higher risk and the annual dollar cost associated with it?

Response:

PGE proposes the HGA because it deals directly with PGE's hydro-related risk. While it is possible in theory to make this analysis to assess a particular element of company-specific risk, the difficulty of doing so reliably and objectively is an underlying factor that leads most regulatory commissions to employ proxy groups to gauge the cost of capital for a particular utility. In any event, Dr. Makholm has not performed the requested analysis.

ICNU/104

PGE/702 Recomputed Using
Strong Price-Hydro Relationship

Exhibit ICNU/104
PGE/702 Recomputed Using "Strong" Price-Hydro Relationship

Historical Hydro Generation (1990-Present)
Model Tariff beginning when balance exceeds $20 MM (3yr Amort to reduce bal to $0, 1yr Lag)

	Hydro Generation Experience			Calc. Excess Power Costs			Net Excess Power Costs of Dead Band				Calc Tariff and Deferral Balance				
Year	Actual	RVM Avg	Difference Mwa (Act - RVM)	2005 RVM FC	Power Cost Delta (000s)	Cumulative	Power Cost Delta (000s)	Less DB	Net Power Cost Delta (000s)	Cumulative	Deferral Beg. Bal	Tariff Amort	Additions	Interest	Deferral End Bal.
1990	592.6	566.5	26.1	36.76	(8,408)	(8,408)	(8,408)	2,500	(5,908)	(5,908)	-	-	(5,908)	(268)	(6,176)
1991	614.3	566.5	47.8	33.25	(13,927)	(22,335)	(13,927)	2,500	(11,427)	(17,335)	(6,176)	-	(11,427)	(519)	(18,122)
1992	509.5	566.5	(57.0)	61.67	30,802	8,467	30,802	(2,500)	28,302	10,967	(18,122)	-	28,302	1,285	11,465
1993	522.3	566.5	(44.2)	57.03	22,094	30,561	22,094	(2,500)	19,594	30,561	11,465	-	19,594	890	31,949
1994	504.8	566.5	(61.8)	63.39	34,290	64,852	34,290	(2,500)	31,790	62,352	31,949	10,649.78	31,790	2,411	55,501
1995	591.3	566.5	24.8	36.96	(8,036)	56,815	(8,036)	2,500	(5,536)	56,815	55,501	18,500.26	(5,536)	1,429	32,893
1996	704.9	566.5	138.4	18.63	(22,588)	34,227	(22,588)	2,500	(20,088)	36,727	32,893	10,964.46	(20,088)	84	1,924
1997	712.9	566.5	146.4	17.34	(22,238)	11,990	(22,238)	2,500	(19,738)	16,990	1,924	-	(19,738)	(896)	(18,710)
1998	589.9	566.5	23.4	37.20	(7,618)	4,371	(7,618)	2,500	(5,118)	11,871	(18,710)	-	(5,118)	(232)	(24,060)
1999	681.8	566.5	115.3	22.36	(22,585)	(18,214)	(22,585)	2,500	(20,085)	(8,214)	(24,060)	(8,020.12)	(20,085)	(1,641)	(37,766)
2000	582.6	566.5	16.1	38.37	(5,410)	(23,623)	(5,410)	2,500	(2,910)	(11,123)	(37,766)	(12,588.63)	(2,910)	(1,276)	(29,363)
2001	427.9	566.5	(138.6)	91.28	110,821	87,197	110,821	(2,500)	108,321	97,197	(29,363)	(9,787.55)	108,321	4,030	92,776
2002	536.3	566.5	(30.2)	51.93	13,741	100,939	13,741	(2,500)	11,241	108,439	92,776	30,925.28	11,241	3,319	76,412
2003	500.7	566.5	(65.8)	64.86	37,391	**138,330**	37,391	(2,500)	34,891	**143,330**	76,412	25,470.50	34,891	3,898	89,730
Average	576.6		10.1		138,330			5,000				66,114	Total Amortization thru 2003		
												89,730	Balance at 12/31/2003		
RVM	566.5											155,844	Net		
												12,514	Interest		
												143,330	Cumulative Net Power Cost Delta		

Price/Hydro	Strong
Negative DB	-2500
Positive DB	2500

ICNU/105

Illustration of HGA Using
Strong Hydro-Price Relationship

Exhibit ICNU/105
Illustration of HGA Using Strong Hydro-Price Relationship

				Calc. Excess Power Costs			Net Excess Power Costs of Dead Band				Calc Tariff and Deferral Balance				
Year	Actual	Mean	Difference Mwa (Act - RVM)	2005 RVM FC	Power Cost Delta (000s)	Cumulative	Power Cost Delta (000s)	Less $2.5 MM	Net Power Cost Delta (000s)	Cumulative	Deferral Beg. Bal	Tariff Amort	Additions	Interest	Deferral End Bal.
1929	466.6	565.4	(98.8)	76.84	66,520	66,520	66,520	(2,500)	64,020	64,020	-	-	64,020	2,907	66,927
1930	456.3	565.4	(109.1)	80.58	77,027	143,546	77,027	(2,500)	74,527	138,546	66,927	22,309.00	74,527	5,411	124,556
1931	457.0	565.4	(108.4)	80.33	76,291	219,838	76,291	(2,500)	73,791	212,338	124,556	41,518.60	73,791	7,122	163,951
1932	557.1	565.4	(8.3)	43.99	3,206	223,044	3,206	(2,500)	706	213,044	163,951	54,650.32	706	4,996	115,003
1933	611.3	565.4	45.9	33.57	(13,490)	209,554	(13,490)	2,500	(10,990)	202,054	115,003	38,334.32	(10,990)	2,983	68,662
1934	569.9	565.4	4.5	40.25	(1,579)	207,975	(1,579)	2,500	-	202,054	68,662	22,887.17	-	2,079	47,853
1935	524.8	565.4	(40.6)	55.72	19,826	227,800	19,826	(2,500)	17,326	219,380	47,853	15,951.06	17,326	2,236	51,463
1936	494.4	565.4	(71.0)	66.75	41,528	269,329	41,528	(2,500)	39,028	258,408	51,463	17,154.43	39,028	3,331	76,668
1937	496.5	565.4	(68.9)	65.99	39,840	309,169	39,840	(2,500)	37,340	295,748	76,668	25,555.87	37,340	4,017	92,469
1938	554.3	565.4	(11.1)	45.01	4,384	313,553	4,384	(2,500)	1,884	297,632	92,469	30,822.91	1,884	2,885	66,415
1939	484.4	565.4	(81.0)	70.38	49,952	363,505	49,952	(2,500)	47,452	345,084	66,415	22,138.48	47,452	4,166	95,895
1940	488.6	565.4	(76.8)	68.86	46,336	409,841	46,336	(2,500)	43,836	388,920	95,895	31,964.88	43,836	4,894	112,660
1941	495.1	565.4	(70.3)	66.50	40,962	450,803	40,962	(2,500)	38,462	427,383	112,660	37,553.46	38,462	5,158	118,727
1942	518.7	565.4	(46.7)	57.93	23,709	474,512	23,709	(2,500)	21,209	448,592	118,727	39,575.66	21,209	4,558	104,918
1943	575.0	565.4	9.6	39.42	(3,308)	471,204	(3,308)	2,500	(808)	447,783	104,918	34,972.71	(808)	3,140	72,277
1944	449.2	565.4	(116.2)	83.16	84,663	555,867	84,663	(2,500)	82,163	529,946	72,277	24,092.33	82,163	5,920	136,267
1945	497.9	565.4	(67.5)	65.48	38,730	594,597	38,730	(2,500)	36,230	566,176	136,267	45,422.32	36,230	5,771	132,846
1946	588.4	565.4	23.0	37.26	(7,501)	587,096	(7,501)	2,500	(5,001)	561,175	132,846	44,281.94	(5,001)	3,795	87,358
1947	586.4	565.4	21.0	37.58	(6,907)	580,189	(6,907)	2,500	(4,407)	556,768	87,358	29,119.42	(4,407)	2,445	56,276
1948	614.4	565.4	49.0	33.06	(14,187)	566,002	(14,187)	2,500	(11,687)	545,082	56,276	18,758.81	(11,687)	1,173	27,004
1949	555.6	565.4	(9.8)	44.53	3,831	569,833	3,831	(2,500)	1,331	546,413	27,004	9,001.33	1,331	878	20,212
1950	664.3	565.4	98.9	25.01	(21,664)	548,169	(21,664)	2,500	(19,164)	527,249	20,212	6,737.32	(19,164)	(258)	(5,948)
1951	651.6	565.4	86.2	27.06	(20,429)	527,741	(20,429)	2,500	(17,929)	509,320	(5,948)	-	(17,929)	(814)	(24,691)
1952	565.8	565.4	0.4	40.91	(136)	527,605	(136)	2,500	-	509,320	(24,691)	(8,230.31)	-	(748)	(17,208)
1953	594.8	565.4	29.4	36.23	(9,324)	518,281	(9,324)	2,500	(6,824)	502,496	(17,208)	-	(6,824)	(310)	(24,342)
1954	649.8	565.4	84.4	27.35	(20,217)	498,064	(20,217)	2,500	(17,717)	484,779	(24,342)	(8,113.97)	(17,717)	(1,542)	(35,487)
1955	603.9	565.4	38.5	34.76	(11,717)	486,347	(11,717)	2,500	(9,217)	475,562	(35,487)	(11,828.84)	(9,217)	(1,493)	(34,367)
1956	643.5	565.4	78.1	28.37	(19,403)	466,944	(19,403)	2,500	(16,903)	458,659	(34,367)	(11,455.79)	(16,903)	(1,808)	(41,623)
1957	560.6	565.4	(4.8)	42.72	1,804	468,748	1,804	(2,500)	-	458,659	(41,623)	(13,874.26)	-	(1,260)	(29,009)
1958	586.9	565.4	21.5	37.50	(7,057)	461,691	(7,057)	2,500	(4,557)	454,103	(29,009)	(9,669.57)	(4,557)	(1,085)	(24,981)
1959	643.8	565.4	78.4	28.32	(19,444)	442,247	(19,444)	2,500	(16,944)	437,158	(24,981)	(8,326.99)	(16,944)	(1,526)	(35,124)
1960	581.5	565.4	16.1	38.37	(5,405)	436,842	(5,405)	2,500	(2,905)	434,253	(35,124)	(11,708.06)	(2,905)	(1,195)	(27,517)
1961	595.8	565.4	30.4	36.07	(9,598)	427,244	(9,598)	2,500	(7,098)	427,155	(27,517)	(9,172.27)	(7,098)	(1,155)	(26,598)
1962	576.6	565.4	11.2	39.17	(3,836)	423,408	(3,836)	2,500	(1,336)	425,819	(26,598)	(8,866.08)	(1,336)	(866)	(19,934)
1963	547.8	565.4	(17.6)	47.37	7,311	430,719	7,311	(2,500)	4,811	430,631	(19,934)	-	4,811	219	(14,904)
1964	589.0	565.4	23.6	37.16	(7,677)	423,043	(7,677)	2,500	(5,177)	425,454	(14,904)	-	(5,177)	(235)	(20,316)
1965	585.0	565.4	19.6	37.81	(6,485)	416,558	(6,485)	2,500	(3,985)	421,469	(20,316)	(6,771.84)	(3,985)	(796)	(18,325)
1966	552.2	565.4	(13.2)	45.77	5,301	421,858	5,301	(2,500)	2,801	424,270	(18,325)	-	2,801	127	(15,397)
1967	574.4	565.4	9.0	39.52	(3,109)	418,750	(3,109)	2,500	(609)	423,661	(15,397)	-	(609)	(28)	(16,033)
1968	590.0	565.4	24.6	37.00	(7,967)	410,782	(7,967)	2,500	(5,467)	418,194	(16,033)	-	(5,467)	(248)	(21,749)

Exhibit ICNU/105
Illustration of HGA Using Strong Hydro-Price Relationship

1969	588.6	565.4	23.2	37.23	(7,559)	403,223	(7,559)	2,500	(5,059)	413,134	(21,749)	(7,249.63)	(5,059)	(888)	(20,447)
1970	531.4	565.4	(34.0)	53.32	15,890	419,113	15,890	(2,500)	13,390	426,525	(20,447)	(6,815.63)	13,390	(11)	(252)
1971	639.7	565.4	74.3	28.98	(18,858)	400,255	(18,858)	2,500	(16,358)	410,167	(252)	-	(16,358)	(743)	(17,353)
1972	672.3	565.4	106.9	23.72	(22,208)	378,048	(22,208)	2,500	(19,708)	390,459	(17,353)	-	(19,708)	(895)	(37,955)
1973	517.5	565.4	(47.9)	58.37	24,501	402,548	24,501	(2,500)	22,001	412,460	(37,955)	(12,651.83)	22,001	(150)	(3,453)
1974	665.1	565.4	99.7	24.88	(21,727)	380,822	(21,727)	2,500	(19,227)	393,233	(3,453)	-	(19,227)	(873)	(23,553)
1975	618.8	565.4	53.4	32.35	(15,129)	365,693	(15,129)	2,500	(12,629)	380,604	(23,553)	(7,850.87)	(12,629)	(1,287)	(29,617)
1976	627.7	565.4	62.3	30.92	(16,868)	348,825	(16,868)	2,500	(14,368)	366,236	(29,617)	(9,872.50)	(14,368)	(1,549)	(35,662)
1977	493.4	565.4	(72.0)	67.11	42,342	391,167	42,342	(2,500)	39,842	406,078	(35,662)	(11,887.39)	39,842	730	16,797
1978	559.5	565.4	(5.9)	43.12	2,236	393,403	2,236	(2,500)	-	406,078	16,797	-	-	-	16,797
1979	508.3	565.4	(57.1)	61.70	30,876	424,279	30,876	(2,500)	28,376	434,454	16,797	-	28,376	1,289	46,461
1980	542.9	565.4	(22.5)	49.14	9,695	433,974	9,695	(2,500)	7,195	441,649	46,461	15,487.02	7,195	1,733	39,903
1981	581.2	565.4	15.8	38.42	(5,311)	428,663	(5,311)	2,500	(2,811)	438,838	39,903	13,300.94	(2,811)	1,080	24,871
1982	637.1	565.4	71.7	29.40	(18,461)	410,202	(18,461)	2,500	(15,961)	422,877	24,871	8,290.40	(15,961)	28	648
1983	634.4	565.4	69.0	29.84	(18,029)	392,172	(18,029)	2,500	(15,529)	407,347	648	-	(15,529)	(705)	(15,587)
1984	619.0	565.4	53.6	32.32	(15,171)	377,002	(15,171)	2,500	(12,671)	394,677	(15,587)	-	(12,671)	(575)	(28,833)
1985	526.5	565.4	(38.9)	55.10	18,785	395,787	18,785	(2,500)	16,285	410,962	(28,833)	(9,610.92)	16,285	(133)	(3,070)
1986	576.4	565.4	11.0	39.20	(3,770)	392,017	(3,770)	2,500	(1,270)	409,692	(3,070)	-	(1,270)	(58)	(4,398)
1987	499.0	565.4	(66.4)	65.08	37,867	429,884	37,867	(2,500)	35,367	445,059	(4,398)	-	35,367	1,606	32,575
1988	503.3	565.4	(62.1)	63.52	34,566	464,450	34,566	(2,500)	32,066	477,125	32,575	10,858.49	32,066	2,443	56,225
1989	544.6	565.4	(20.8)	48.53	8,851	473,301	8,851	(2,500)	6,351	483,476	56,225	18,741.82	6,351	1,991	45,825
1990	602.7	565.4	37.3	34.95	(11,415)	461,886	(11,415)	2,500	(8,915)	474,561	45,825	15,275.10	(8,915)	983	22,618
1991	602.6	565.4	37.2	34.97	(11,389)	450,497	(11,389)	2,500	(8,889)	465,672	22,618	7,539.40	(8,889)	281	6,471
1992	485.4	565.4	(80.0)	70.02	49,081	499,578	49,081	(2,500)	46,581	512,253	6,471	-	46,581	2,115	55,167
1993	505.8	565.4	(59.6)	62.61	32,701	532,279	32,701	(2,500)	30,201	542,454	55,167	18,389.01	30,201	3,042	70,021
1994	498.5	565.4	(66.9)	65.26	38,258	570,537	38,258	(2,500)	35,758	578,212	70,021	23,340.25	35,758	3,744	86,183
1995	594.5	565.4	29.1	36.28	(9,241)	561,296	(9,241)	2,500	(6,741)	571,471	86,183	28,727.57	(6,741)	2,303	53,017
1996	652.5	565.4	87.1	26.92	(20,531)	540,765	(20,531)	2,500	(18,031)	553,440	53,017	17,672.46	(18,031)	786	18,100
1997	694.2	565.4	128.8	20.18	(22,771)	517,994	(22,771)	2,500	(20,271)	533,169	18,100	-	(20,271)	(921)	(3,092)
1998	555.1	565.4	(10.3)	44.72	4,043	522,036	4,043	(2,500)	1,543	534,711	(3,092)	-	1,543	70	(1,479)
1999	681.8	565.4	116.4	22.18	(22,619)	499,417	(22,619)	2,500	(20,119)	514,592	(1,479)	-	(20,119)	(914)	(22,512)
2000	582.6	565.4	17.2	38.20	(5,750)	493,668	(5,750)	2,500	(3,250)	511,343	(22,512)	(7,503.93)	(3,250)	(829)	(19,087)
2001	427.9	565.4	(137.5)	90.88	109,473	603,141	109,473	(2,500)	106,973	618,316	(19,087)	-	106,973	4,858	92,745
2002	536.3	565.4	(29.1)	51.54	13,145	616,286	13,145	(2,500)	10,645	628,961	92,745	30,914.90	10,645	3,291	75,766
2003	500.7	565.4	(64.7)	64.46	36,548	652,834	36,548	(2,500)	34,048	663,009	75,766	25,255.41	34,048	3,840	88,399
	565.4											Total	663,009		
												Average	8,840		

ICNU/105
Falkenberg/2

ICNU/106

Illustration of Hypothetical Hydro Hedge

Exhibit ICNU/106
Illustration of Hypothetical Hydro Hedge
(Based on 29-03 Data)

STRONG RELATIONSHIP HYDRO AND PRICES

Rank	Percentile	Hydro Deficit - mWa	Price - $/mWh	Total Cost	Expected Payout
1	1.33%	-137.50	90.88	109,473	1,460
2	2.67%	-116.22	83.16	84,663	2,588
3	4.00%	-109.12	80.58	77,027	3,615
4	5.33%	-108.42	80.33	76,291	4,633
5	6.67%	-98.82	76.84	66,520	5,520
6	8.00%	-81.02	70.38	49,952	6,186
7	9.33%	-80.02	70.02	49,081	6,840
8	10.67%	-76.82	68.86	46,336	7,458
9	**12.00%**	**-72.02**	**67.11**	**42,342**	**8,022**
10	13.33%	-71.02	66.75	41,528	8,576
11	14.67%	-70.32	66.50	40,962	9,122
12	16.00%	-68.92	65.99	39,840	9,654
13	17.33%	-67.52	65.48	38,730	10,170
14	18.67%	-66.92	65.26	38,258	10,680
15	20.00%	-66.42	65.08	37,867	11,185
16	21.33%	-64.72	64.46	36,548	11,672
17	22.67%	-62.12	63.52	34,566	12,133
18	24.00%	-59.62	62.61	32,701	12,569
19	25.33%	-57.12	61.70	30,876	12,981
20	26.67%	-47.92	58.37	24,501	13,307
21	28.00%	-46.72	57.93	23,709	13,624
22	29.33%	-40.62	55.72	19,826	13,888
23	30.67%	-38.92	55.10	18,785	14,138
24	32.00%	-34.02	53.32	15,890	14,350
25	33.33%	-29.12	51.54	13,145	14,526
26	34.67%	-22.52	49.14	9,695	14,655
27	36.00%	-20.82	48.53	8,851	14,773
28	37.33%	-17.62	47.37	7,311	14,870
29	38.67%	-13.22	45.77	5,301	14,941
30	40.00%	-11.12	45.01	4,384	14,999
31	41.33%	-10.32	44.72	4,043	15,053
32	42.67%	-9.82	44.53	3,831	15,104
33	44.00%	-8.32	43.99	3,206	15,147

NO RELATIONSHIP HYDRO AND PRICES

Rank	Percentile	Hydro Deficit - mWa	Price - $/mWh	Total Cost	Expected Payout
1	1.33%	-137.50	40.97	-49,350	-658
2	2.67%	-116.22	40.97	-41,711	-1,214
3	4.00%	-109.12	40.97	-39,163	-1,736
4	5.33%	-108.42	40.97	-38,912	-2,255
5	6.67%	-98.82	40.97	-35,466	-2,728
6	8.00%	-81.02	40.97	-29,078	-3,116
7	9.33%	-80.02	40.97	-28,719	-3,499
8	10.67%	-76.82	40.97	-27,571	-3,866
9	**12.00%**	**-72.02**	**40.97**	**-25,848**	**-4,211**
10	13.33%	-71.02	40.97	-25,489	-4,551
11	14.67%	-70.32	40.97	-25,238	-4,887
12	16.00%	-68.92	40.97	-24,735	-5,217
13	17.33%	-67.52	40.97	-24,233	-5,540
14	18.67%	-66.92	40.97	-24,018	-5,860
15	20.00%	-66.42	40.97	-23,838	-6,178
16	21.33%	-64.72	40.97	-23,228	-6,488
17	22.67%	-62.12	40.97	-22,295	-6,785
18	24.00%	-59.62	40.97	-21,398	-7,071
19	25.33%	-57.12	40.97	-20,500	-7,344
20	26.67%	-47.92	40.97	-17,199	-7,573
21	28.00%	-46.72	40.97	-16,768	-7,797
22	29.33%	-40.62	40.97	-14,579	-7,991
23	30.67%	-38.92	40.97	-13,968	-8,177
24	32.00%	-34.02	40.97	-12,210	-8,340
25	33.33%	-29.12	40.97	-10,449	-8,480
26	34.67%	-22.52	40.97	-8,083	-8,587
27	36.00%	-20.82	40.97	-7,472	-8,687
28	37.33%	-17.62	40.97	-6,324	-8,771
29	38.67%	-13.22	40.97	-4,745	-8,834
30	40.00%	-11.12	40.97	-3,991	-8,888
31	41.33%	-10.32	40.97	-3,704	-8,937
32	42.67%	-9.82	40.97	-3,525	-8,984
33	44.00%	-8.32	40.97	-2,986	-9,024

Exhibit ICNU/106
Illustration of Hypothetical Hydro Hedge
(Based on 29-03 Data)

34	45.33%	-5.92	43.12	2,236	15,177
35	46.67%	-4.82	42.72	1,804	15,201
36	**48.00%**	**0.38**	**40.91**	**-136**	**-6,497**
37	49.33%	4.48	40.25	-1,579	-6,495
38	50.67%	8.98	39.52	-3,109	-6,474
39	52.00%	9.58	39.42	-3,308	-6,432
40	53.33%	10.98	39.20	-3,770	-6,388
41	54.67%	11.18	39.17	-3,836	-6,338
42	56.00%	15.78	38.42	-5,311	-6,287
43	57.33%	16.08	38.37	-5,405	-6,216
44	58.67%	17.18	38.20	-5,750	-6,144
45	60.00%	19.58	37.81	-6,485	-6,067
46	61.33%	20.98	37.58	-6,907	-5,981
47	62.67%	21.48	37.50	-7,057	-5,889
48	64.00%	22.98	37.26	-7,501	-5,795
49	65.33%	23.18	37.23	-7,559	-5,695
50	66.67%	23.58	37.16	-7,677	-5,594
51	68.00%	24.58	37.00	-7,967	-5,491
52	69.33%	29.08	36.28	-9,241	-5,385
53	70.67%	29.38	36.23	-9,324	-5,262
54	72.00%	30.38	36.07	-9,598	-5,138
55	73.33%	37.18	34.97	-11,389	-5,010
56	74.67%	37.28	34.95	-11,415	-4,858
57	76.00%	38.48	34.76	-11,717	-4,706
58	77.33%	45.88	33.57	-13,490	-4,549
59	78.67%	48.98	33.06	-14,187	-4,370
60	80.00%	53.38	32.35	-15,129	-4,180
61	81.33%	53.58	32.32	-15,171	-3,979
62	82.67%	62.28	30.92	-16,868	-3,776
63	84.00%	68.98	29.84	-18,029	-3,551
64	85.33%	71.68	29.40	-18,461	-3,311
65	86.67%	74.28	28.98	-18,858	-3,065
66	88.00%	78.08	28.37	-19,403	-2,814
67	89.33%	78.38	28.32	-19,444	-2,555
68	90.67%	84.38	27.35	-20,217	-2,296
69	92.00%	86.18	27.06	-20,429	-2,026
70	93.33%	87.08	26.92	-20,531	-1,754

34	45.33%	-5.92	40.97	-2,125	-9,052
35	46.67%	-4.82	40.97	-1,730	-9,075
36	48.00%	0.38	40.97	136	9,075
37	49.33%	4.48	40.97	1,608	9,073
38	50.67%	8.98	40.97	3,223	9,052
39	52.00%	9.58	40.97	3,438	9,009
40	53.33%	10.98	40.97	3,940	8,963
41	54.67%	11.18	40.97	4,012	8,911
42	56.00%	15.78	40.97	5,663	8,857
43	57.33%	16.08	40.97	5,771	8,782
44	58.67%	17.18	40.97	6,167	8,705
45	60.00%	19.58	40.97	7,027	8,623
46	61.33%	20.98	40.97	7,529	8,529
47	62.67%	21.48	40.97	7,709	8,428
48	64.00%	22.98	40.97	8,247	8,326
49	65.33%	23.18	40.97	8,319	8,216
50	66.67%	23.58	40.97	8,463	8,105
51	68.00%	24.58	40.97	8,821	7,992
52	69.33%	29.08	40.97	10,437	7,874
53	70.67%	29.38	40.97	10,544	7,735
54	72.00%	30.38	40.97	10,903	7,595
55	73.33%	37.18	40.97	13,344	7,449
56	74.67%	37.28	40.97	13,379	7,271
57	76.00%	38.48	40.97	13,810	7,093
58	77.33%	45.88	40.97	16,466	6,909
59	78.67%	48.98	40.97	17,579	6,689
60	80.00%	53.38	40.97	19,158	6,455
61	81.33%	53.58	40.97	19,230	6,199
62	82.67%	62.28	40.97	22,352	5,943
63	84.00%	68.98	40.97	24,757	5,645
64	85.33%	71.68	40.97	25,726	5,315
65	86.67%	74.28	40.97	26,659	4,972
66	88.00%	78.08	40.97	28,022	4,616
67	**89.33%**	**78.38**	**40.97**	**28,130**	**4,243**
68	90.67%	84.38	40.97	30,284	3,868
69	92.00%	86.18	40.97	30,930	3,464
70	93.33%	87.08	40.97	31,253	3,052

Exhibit ICNU/106
Illustration of Hypothetical Hydro Hedge
(Based on 29-03 Data)

71	94.67%	98.88	25.01	-21,664	-1,480	71	94.67%	98.88	40.97	35,488	2,635
72	96.00%	99.68	24.88	-21,727	-1,191	72	96.00%	99.68	40.97	35,775	2,162
73	97.33%	106.88	23.72	-22,208	-901	73	97.33%	106.88	40.97	38,359	1,685
74	98.67%	116.40	22.18	-22,619	-605	74	98.67%	116.40	40.97	41,774	1,173
75	100.00%	128.78	20.18	-22,771	-304	75	100.00%	128.78	40.97	46,219	616

ICNU/107

PGE Response to ICNU Data Request No. 1.16

December 29, 2004

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 1.16
Dated December 10, 2004
Question 016

Request:

Questions Related to the testimony of Jim Lobdell:

Describe in as much detail as possible, and be as specific as possible in defining what would represent to PGE a hydro hedge that would sufficiently protect the stability of the Company's earnings to eliminate the need for the proposed HGA.

Response:

We would require a hedge with two primary characteristics:

1) Its payoff structure would have to be reasonably correlated with the combined output of our company-owned facilities on the Clackamas and Deschutes Rivers and our contractual shares of facilities on the middle stretch of the Columbia River. If based on precipitation and/or stream flows, it would require measurements at many locations, particularly in the case of precipitation.
2) The payoff structure would have to cover the full value of fluctuations in PGE's hydro production (i.e., full market price times hydro variance quantity), rather than the delta in actual market price from expected market price times hydro variance quantity. For example, if hydro production was 100 MWh less than expected, and the market electric price was $50/MWh, rather than a previously expected price of $45/MWh, then the payoff structure would have to cover the full $5,000 (100 MWh x $50/MWh) replacement power cost, rather than only $500 (100 MWh x ($50/MWh - $45/MWh).

See PGE's Response to ICNU Data Request No. 015 for a discussion of why it is not possible to meet the second characteristic.

ICNU/108

PGE Response to ICNU Data Request No. 1.15

December 29, 2004

TO: Melinda Davison
ICNU

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
UE-165
PGE Response to ICNU Data Request 1.15
Dated December 10, 2004
Question 015

Request:

Questions Related to the testimony of Jim Lobdell:

Provide any more detailed or specific documentation PGE has developed concerning the details of the hydro hedge the Company sought.

Response:

PGE sought to cover the risk associated with the value of fluctuations in hydro production from company-owned facilities located on the Clackamas and Deschutes Rivers, and contracts based on the output of facilities located on the middle portion of the Columbia River. See PGE's Response to ICNU Data Request No. 016 for more details on the nature of the risk PGE sought to hedge. We discussed possible products with four types of potential counterparties.

i) We investigated products available on the Intercontinental Exchange (ICE), an internet platform offering a variety of products. However, ICE does not offer any products based on hydro exposure. Instead, ICE offers products that could possibly hedge only a small portion of our risk, based simply on price.

ii) We had discussions with brokers[1] that offer weather and non-standard derivatives. These brokers offer precipitation and temperature-based products. However, they do not offer anything tailored to our specific need, a product related to hydro production on the Clackamas, Deschutes, and mid-Columbia, or at least based on water flows on these rivers. It might be possible to find a product based simply on run-off at The Dalles, but

[1] We removed the names of specific potential counterparties, so that we could offer this response on a non-confidential basis.

that could differ from production at the mid-Columbia facilities, and it would almost certainly differ from production on the Clackamas and Deschutes Rivers. In addition, the relationship between precipitation and stream flows is itself very complex. Finally, the relevant precipitation measurements might have to be taken at numerous sub-basin locations, making for complicated pay-off calculations and hence lack of commercial appeal.

iii) We talked with bankers. However, they are generally unwilling to offer products based on the flows relevant to PGE, as they are unable to effectively hedge that risk. They might be willing to enter into agreements based on flow at The Dalles as a secondary consideration to market price.

iv) We discussed possible products with one possible counterparty who is willing to consider a more customized product, based on some combination of stream flows, snow pack, and precipitation. However, as is the case with all of the possible counterparties we spoke with, this counterparty would only cover part of the risk we are exposed to. The product, like those considered by the bankers and other possible counterparties, would essentially have two triggers, one based on weather or stream flows, and another based on the difference between the actual market electric price and some expectation of this price at the time the agreement was made. Hence, if some proxy indicated one million MWh lower hydro output, and market electric prices were $50, compared to an expectation of $45, the pay-off would be the one million MWh decrease in output, multiplied by the $5 increase in market price over expectations, or $5 million. However, the increased cost to PGE, to purchase one million MWh to replace the deficient hydro generation, would be $50 million.

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Attorneys at Law
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Suite 400
333 S.W. Taylor
Portland, OR 97204

February 14, 2005

Via Electronic and U.S. Mail

Public Utility Commission
Attn: Filing Center
550 Capitol St. NE #215
P.O. Box 2148
Salem OR 97308-2148

Re: In the Matter of PORTLAND GENERAL ELECTRIC Application for a Hydro Generation Power Cost Adjustment Mechanism
Docket No. UE 165

Dear Filing Center:

Enclosed please find an original and six (6) copies of the Direct Testimony of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities in the above-captioned Docket.

Please return a file-stamped copy of this document in the self-addressed, stamped envelope provided. Thank you for your assistance.

Sincerely,

/s/ Christian Griffen
Christian W. Griffen

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Direct Testimony of Randall J. Falkenberg on behalf of the Industrial Customers of Northwest Utilities upon the parties listed below by causing the same to be mailed, postage-prepaid, through the U.S. Mail.

Dated at Portland, Oregon, this 14th day of February, 2005.

/s/ Christian Griffen
Christian W. Griffen

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